Response to Public Comments
EPA Comments
5/10/10

I. SCR is Cost Effective Based upon NDDH's Inflated Cost Estimates

Comment 1: – NDDH failed to conduct an adequate comparison of the average cost effectiveness of SCR at MRYS with other sources.

Response: Disagree – The NDDH reviewed all BACT determinations for coal-fired power plants contained in the RACT/BACT/LAER Clearinghouse from 2005 to the present. This review was not limited to sources in nearby states as erroneously stated by EPA. Unfortunately, cost information for SCR was not available for most of the facilities. Older determinations were not considered because of the rapid increase in SCR cost since 2004.[1] So, the Department also reviewed cost estimates for SCR in BART analyses from states as far away as Oregon and Alaska. The BART estimates from western states were chosen because of availability and local cost considerations (e.g., labor costs, transportation costs, etc.) which are expected to be similar to those in North Dakota.

Comment 2: – The draft BACT determination is also deficient because it compared the calculated cost effectiveness of LDSCR at MRYS with the average of the costs of controls from within the small group selected by NDDH, instead of comparing costs with individual costs at other facilities.

Response: Disagree – The NDDH compared both the average cost and the highest individual costs for the limited data that was available for BACT determinations. In the MRYS determination, the NDDH states "The cost effectiveness of SCR at M.R. Young Station is higher than any other facility in Table 7" (note – the reference to Table 7 is incorrect, it should be Table 8; Table 7 lists CO_2 emissions). The NDDH reviewed every BACT determination for coal-fired power plants from 2005 to the present. Very little information was available on the cost of SCR and what information was available was probably not verified by the reviewing agency. The Department expanded its review to available BART information.

Comment 3: The requirement in the Clean Air Act is for the "Best" available controls, not the average available controls.

Response: The NDDH agrees that the Best Available Control Technology is required. Minnkota evaluated SCR + ASOFA with a control efficiency of 93.8%. This is the highest removal efficiency found in any BACT or BART analysis for a coal-fired boiler using SCR. This technology is anything but average. The average cost for BACT for sources reviewed was evaluated because of the huge discrepancy in the projected BACT cost effectiveness (from \$1,511/ton to \$4,037/ton – both for new facilities, both pulverized coal-fired units with similar baseline emissions). The average indicates the high end of the range may not be valid. The cost effectiveness at the end is approximately \$1,400/ton higher than the next highest BACT analysis.

<u>Comment 4</u>: WDEQ considers \$4,156/ton and incremental cost of \$10,303/ton to be reasonable.
<u>Response</u>: The NDDH does not consider an incremental cost of \$10,303/ton to be reasonable. As pointed out in the analysis, several other states also do not consider it reasonable. EPA in their analysis for the Deseret Power Plant[2] states "The incremental cost of \$10,540 per ton of SO_2 to install a wet scrubber rather than a dry scrubber is **too high to justify the expenditure**." The analysis goes on to state "Limestone injection and wet FGD is eliminated as a BACT control option, based on economic impacts of wet FGD (**unacceptably high incremental SO_2 removal costs**) ..." As indicated earlier, the unacceptably high incremental SO_2 removal cost was \$10,540 per ton. In the response to comments on the Deseret Power Plant[3], EPA provided information on other PSD BACT determinations where incremental costs were considered excessive. These included:

Facility	**State**	**Pollutant**	**Incremental Cost ($/ton)**
Longleaf Energy Station	GA	SO_2	8,964
Cargill's Blair Corn Million	NE	SO_2	5,900
ADM Columbus Corn Milling	NE	NO_x	5,600
MDU/Westmoreland Gascoyne 175	ND	NO_x	14,339
Red Rail Energy	ND	SO_2	10,252
Wygen 3	WY	PM	14,609

Based on the average of the two catalyst replacement scenarios, the incremental cost effectiveness of LDSCR + ASOFA was \$9,207/ton for Unit 1 and \$10,872/ton for Unit 2. For TESCR + ASOFA, the incremental cost effectiveness was \$10,872/ton and \$12,578/ton for Units 1 and 2, respectively. The NDDH considers these incremental cost effectiveness values to be excessive.

<u>Comment 5</u>: Wisconsin Public Service Company's Weston 4 plant had a cost effectiveness of \$6,116/ton but was not considered by the NDDH.

<u>Response</u>: The Wisconsin Public Services Company's BACT determination was not considered because the estimated removal efficiency of SCR was 53.3% and other concerns (see Response to Comment 7). As the NSR Manual[4] points out, underestimating the control efficiency can inflate the cost effectiveness (and incremental cost effectiveness) of the control technology.

<u>Comment 6</u>: The baseline emission rate in the Sherco #2 is 0.20 lb/10^6 Btu and SCR at MRYS can expect to have a higher removal efficiency than Sherco #2.

<u>Response</u>: Minnkota used a 90% removal efficiency for SCR with an expected emission rate of 0.05 lb/10^6 Btu (including ASOFA). The expected emission rate at Sherco #2 with combustion optimization and SCR is 0.08 lb/10^6 Btu. The SCR was expected to reduce emissions only 47%. Had the Sherco #2 analysis used an expected emission rate of 0.05 lb/10^6 Btu, the cost effectiveness would have been $2,841/ton, a difference of $1,759/ton. As shown by the Dry Fork BACT analysis[5], an emission rate of 0.05 lb/10^6 Btu is achievable for a much lower baseline emission rate than that at MRYS. The NDDH believes that when comparing the cost effectiveness of a technology to cost borne by other facilities, a comparison must be made of the expected efficiency and expected emission rate to have a common basis of comparison. As indicated in the draft BACT analysis, using low efficiencies (i.e., higher controlled emission rates) leads to inflated cost effectiveness estimates.

Comment 7: The commenter provided several examples of documents where costs for NO_x control were presumed to be cost effective including refineries, State guidance document, EPA letters to State Agencies, survey results, consent decrees, Laramie Cement Plant BACT analysis, RBLC documents and EAB ruling.

Response: The NSR Manual[4] states "In essence, if the cost of reducing emissions with the top control alternative, expressed in dollars per ton, is on the same order as the cost previously borne by other sources of the same type in applying the control alternative, the alternative should initially be considered economically achievable, and therefore acceptable as BACT" (emphasis added). The NSR Manual[4] goes on to say "Where the cost effectiveness of a control alternative for the specific source being reviewed is within the range of normal costs for that control alternative, the alternative may also be eligible for elimination in limited circumstances. This may occur, for example, where a control alternative has not been required as BACT (or its application as BACT has been extremely limited) and there is a clear demarcation between recent BACT control costs in that source category and the control costs for sources in that source category which have been driven by other constraining factors (e.g., need to meet a PSD increment or a NAAQS)" (emphasis added).

Coal-fired boilers are a different type of source than a refinery, cement plant, chemical plant, combustion turbine, etc. The RBLC classifies these sources separately. NSPS and MACT standards regulate these type of sources separately and they are listed as separate source categories in the definition of major stationary source in the PSD regulations. The NDDH believes that costs for controls on a coal-fired power plant should be compared to costs at other coal-fired power plants.

The commenter inappropriately provided data on many other source categories other than coal-fired boilers. Of the 14 facilities the commenter indicated in the RBLC with a higher cost effectiveness only two were coal-fired boilers. The Weston Power Plant #4 was reviewed by the NDDH prior to the draft BACT determination. The RBLC indicated a cost effectiveness of $6,116/ton; however, the efficiency of the SCR was only listed at 53.3%. This low efficiency could lead to an inflated cost effectiveness. Other issues with the analysis were that the baseline emission rate was set at the NSPS limit, not actual expected emission rate, and the annual capacity factor was only 85%. The NSR Manual[4] (Section IV.D.2.b) states "The NSPS/NESHAP requirements or the application of controls, including other controls necessary to comply with state or local air pollution regulations, are not considered in calculating the baseline emissions." The MRYS analysis set the baseline at the actual emission rate and used a capacity factor of 97.3% for Unit 1 and 98.9% for Unit 2. Had 90% removal efficiency, 95% availability and a baseline emission rate of 0.30 lb/10^6 Btu (typical for pulverized units) been used in the Weston economic analysis, the cost effectiveness of SCR would have been as low as $1,621/ton. When comparing cost effectiveness of similar sources, the NDDH believes you have to make an apples-to-apples comparison.

The Keystone Cogeneration Systems, Inc. facility, which commenter also listed, is no longer in the RBLC. The Comprehensive Report provided by the commenter for this facility indicates this is probably not a BACT determination. The report suggests it is a case-by-case determination, perhaps LAER. The Comprehensive Report also indicates SNCR can be used to achieve the NO_x emission limit at a cost effectiveness of $3,980/ton. Since this is apparently not a BACT determination, the cost effectiveness is not a fair comparison to MRYS.

The commenter also suggested that 90% removal by SCR in the BART analysis for Sherco #2 is not available and the cost comparison is appropriate. The BART analysis for Sherco #2 indicates that SOFA+ SCR will only achieve an emission rate of 0.08 $lb/10^6$ Btu. The NDDH believes 0.05 $lb/10^6$ Btu may be achievable (Wygen 3 and Dry Fork Power plants are expected to achieve this rate). In the BART analysis for Leland Olds Unit 1, the NDDH used an 80% removal efficiency and an expected emission rate of 0.057 $lb/10^6$ Btu. Had 0.05 $lb/10^6$ Btu been used as the expected emission rate (75% reduction), the cost effectiveness would have been as low as $2,841/ton.

The NSR Manual[4] states that a comparison of the expected costs should be made to cost previously borne by other sources of the same type. Guidance documents from States and EPA do not necessarily reflect costs borne by the same source type or category. The only true comparison is from BACT determinations for the same source category that were actually constructed.

Comment 8: The Clean Air Interstate Rule (CAIR), the Best Available Retrofit Technology (BART) Guidelines, and revisions to the New Source Performance Standards (NSPS) for Electric Utility Steam Generating Units all support the position that SCR is technically feasible and cost effective.

Response: The NSR Manual[4] states "Technical feasibility of technology transfer control candidates generally is assessed based on an evaluation of pollutant-bearing gas stream characteristics for the proposed source and other source types to which the control has been applied previously." The NDDH has not found any analysis of the flue gas characteristic of North Dakota lignite in the record for the CAIR, BART or NSPS rules. The commenter did not provide any such analysis to support the technical feasibility claim for North Dakota lignite in these rules. The flue gas characteristics of a cyclone-fired boiler combusting North Dakota lignite is different from other coal-fired combustors. CERAM Environmental, Inc. has stated in their proposal to Minnkota that they are unaware of any SCR application experience in the industry with the level and form of sodium in the MRYS ash. Haldor Topsoe, Inc. has stated in their proposal that the potential exists that physical deactivation due to catalyst blinding and plugging could be severe enough to make SCR a nonviable option for controlling NO_x emissions. Both vendors would not supply a catalyst life guarantee without successful pilot-scale testing. The pilot testing would be used to determine if SCR can be successfully applied at the MRYS.

The costs for SCR in the CAIR, BART Guideline and NSPS are general cost estimates based on high dust SCR. These estimates do not account for site specific circumstances and are not applicable to low dust and tail end SCR because of the additional cost for reheating the flue gas. Again, these rules did not review the flue gas characteristics of North Dakota lignite which will affect the design and operation of an SCR system. The comparison of SCR costs estimated in the preparation of CAIR, the NSPS and the BART Guideline is inappropriate.

Comment 9: The cost estimate provided by Minnkota must be considered cost effective.

Response: The NDDH did not say that the cost effectiveness was excessive. The draft BACT determination said the cost effectiveness was high. This high cost effectiveness, high incremental cost, additional pollutants emitted and a major question about technical feasibility of SCR to MRYS were all factors in rejecting SCR as BACT. The NDDH still considers the cost effectiveness and incremental cost effectiveness to be high – as high as those for any other BACT source with similar emission limits (or efficiencies), availability, and calculation of baseline emissions where SCR was required. However, the NDDH's final determination is that SCR (HDSCR, LDSCR and TESCR) is not considered technically feasible for MRYS. Therefore, the costs for SCR are irrelevant.

Comment 10: The commenter provided information that other reasons were involved in the rejection of an emission limit of 0.043 $lb/10^6$ Btu at Wygen 2 and SNCR at 0.05 $lb/10^6$ Btu at an ADM facility in Nebraska.

Response: The NDDH agrees that other factors contributed to the rejection of the listed emission rates at these two facilities. However, other facilities where a technology or emission rate were rejected include:

Facility	Incremental Cost
River Hill Power Company	$ 5,000/ton
Long Leaf Generating Station	$ 8,964/ton
Cargill, Inc – Blair Plant	$ 5,900/ton
Sandy Creek Station	$ 5,000/ton
Red Trail Energy	$ 10,252/ton
Spiritwood Station	$ 12,902/ton

The commenter claims that EPA had other reasons for rejecting wet scrubbing at Deseret Power[2]. In their statement of basis EPA stated "The incremental cost of $10,540 per ton of SO_2 to install a wet scrubber rather than a dry scrubber is too high to justify the expenditure." The statement of basis[2] also states "limestone injection + wet FGD is eliminated as a BACT control option based on economic impacts of wet FGD (unacceptably high incremental SO_2 removal costs)…" Although EPA may have had other reasons for rejecting wet FGD, the statement of basis suggests EPA considered $10,540/ton incremental cost to be excessive for wet FGD. Excessive costs are valid reasons for rejecting a technology. EPA implies that SO_2 control costs should not be compared to NO_x control costs. In the Response to Comments on the Deseret Power Plant (p.30), EPA Region 8 also made a comparison of costs for SO_2 removal to costs for NO_x and PM_{10} removal. The NDDH has never made a distinction between these pollutants for cost comparisons in a BACT determination. This is also true for MRYS.

II. NDDH Draft BACT Determination Failed to Follow EPA's NSR Workshop Manual

Comment 1: NDDH was and is required to conduct its BACT determination in accordance with the NSR Manual and OAQPS Control Cost Manual.

Response: The NSR Manual[4] (Section IV.D.2.a) states "The basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source [such as the OAQPS Control Cost Manual (Fourth Edition)]" (emphasis added). It goes on to state "Consistency in the approach to decision-making is a primary objective of the top-down BACT approach. In order to maintain and improve the consistency of BACT decisions made on the basis of cost and economic considerations, procedures for estimating control equipment costs are based on EPA's OAQPS Control Cost Manual and are set forth in Appendix B of this document. Applicants should closely follow the procedures in the appendix and any deviations should be clearly presented and justified in the documentation of the BACT analysis."

"Total cost estimates of options developed for BACT analyses should be on the order of plus or minus 30 percent accuracy. If more accurate cost data are available (such as specific bid estimates), these should be used. However, these types of costs may not be available at the time permit applications are being prepared. Costs should also be site specific" (emphasis added).

The first citation above suggests that cost estimates should be from equipment vendor data or by an estimating source, not necessarily the OAQPS Control Cost Manual[6]. The second citation seems to conflict with the first by requiring costs be based on the OAQPS Control Cost Manual. The third citation indicates costs should be site specific. The OAQPS Manual provides a generic methodology for calculating SCR costs but is not site specific.

The OAPQS Manual[6], Section 2.4 for SCR, states "The cost estimating methodology presented here provides a tool to estimate study-level costs for **high-dust SCR systems**. Actual selection of the most cost effective option should be based on a detailed engineering study and cost quotations from the system suppliers" (emphasis added). It also states "This report is based on the high-dust SCR system because it is the most common design. A low-dust configuration would cost somewhat less because the required catalyst volume is smaller and ash hoppers on the SCR reactor are not required. The cost methodology is valid for a low-dust SCR system because the cost reductions are expected to be within the range of uncertainty for study-level costs. The costs for the tail end arrangement, however, cannot be estimated from this report because they are significantly higher than the high-dust SCR systems due to flue gas reheating requirements" (emphasis added).

The NDDH believes the OAQPS Cost Manual[6] was not intended for making BACT determinations for LDSCR and TESCR. The Cost Manual clearly states that selection of the most cost effective option study be based on a detailed (i.e., site specific) engineering analysis with vendor quotes. It is also clear the OAQPS Manual cannot be used to estimate TESCR. Although the manual states that it can be used for LDSCR, a closer examination suggests it cannot be used for such purpose. In Section 2.2.3 of the manual for Low Dust SCR it is stated "Flue gas temperatures generally do not decrease to the point where reheating is required. However, an increase in the size of the economizer bypass duct may be required to maintain the flue gas temperature within the optimum range." Minnkota's evaluation of LDSCR has found that flue gas reheating will be necessary. Since the manual did not anticipate reheating the flue gas for LDSCR, the manual cannot be used for cost estimating for the same reason it cannot be for TESCR (i.e. reheat costs). Based on the statements in the OAQPS Manual[6] that a detailed engineering study should be used to determine the most cost effective option (i.e. BACT) and LDSCR/TESCR cannot be estimated by using the manual, Minnkota has selected a methodology for the capital cost estimate consistent with Current Capital Cost and Cost-Effectiveness of Power Emissions Control Technologies[7]" by Cichanowicz. Since the cost estimate is site specific, with vendor quotes and uses a referenced source, the methodology is acceptable for this BACT determination.

A. Inflated Capital Cost Estimates and Cost Methods

Comment 2: MRYS cost estimate is significantly higher than other sources which range from \$100-\$200/kw including two projects in North Dakota which had estimated costs of \$117/kw to \$132/kw.

Response: The three projects in North Dakota which had final applications and were subject to public comment were the Gascoyne 175 plant, Gascoyne 500 plant and the Spiritwood Station. The Gascoyne 175 SCR capital cost was estimated at \$177/kw, Gascoyne 500 at \$134/kw and the Spiritwood Station was approximately \$235/kw. The Gascoyne 175 cost references the 1990 OAQPS Cost Manual for its basis and the Spiritwood Station references the 2002 OAQPS Cost Manual[6]. The Gascoyne 500 estimate follows the procedures of the OAQPS Cost Manual; however, it does not include costs for reheating the flue gas. As indicated in the Response to Comment 11, the OAQPS Cost Manual is not appropriate for estimating the cost of low-dust SCR. The NDDH did not object to these cost estimates since they were obviously conservative and the incremental cost between SCR and SNCR was obviously excessive. Only the Spiritwood Station was built, without SCR.

The commenter provided information that the projected cost of LDSCR at WE Energies South Oak Creek Units 5-8 was approximately \$168/kw; however, in Footnote 34, the commenter also indicates that information submitted to the Public Service Commission of Wisconsin indicates a higher cost. The commenter does not provide the revised estimated cost. Without a detailed cost estimate to evaluate, it is impossible to tell the differences between MRYS estimate and the South Oak Creek estimate. Since the BACT determination is based on a site specific cost estimate, the information for the South Oak Creek estimate is of little value. The commenter also indicates that the PSE&G retrofitted the Mercer Station Units 1 and 2 with cold-side SCRs with a capital cost of approximately \$185/kw. Again, no details were provided.

III. Minnkota's Cost Estimate

Comment: EPA objected to Minnkota's cost estimate for several reasons. These included:

1) Use of a levelized cost
2) Failure to use the EPA Air Pollution Control Cost Manual.

3) Inclusion of startup expenses, cost escalation, allowance for funds during construction (AFDC) and owner's costs. EPA also objected to the amount included for these items.
4) Inflated Annual Cost Estimates & Cost Methods
   a) Annual Maintenance costs
   b) Annual Reagent costs
   c) Annual Electricity costs
   d) Catalyst Replacement costs
   e) Natural gas for flue gas reheating

<u>Response</u>:

1) Use of a levelized cost – EPA's objection to the use of a levelized annual cost is without merit. The NSR Manual[4], Appendix B, Section II, page b.4 states "The permit application should use the levelized annual cost approach for consistency in BACT cost analyses." Use of a levelized cost estimate is consistent with the NSR Manual.

2) Failure to use the EPA Air Pollution Control Cost Manual - The Control Cost Manual cannot be used for estimating the cost of TESCR and LDSCR (see Response to Comment II.1).

3) Inclusion of startup expenses, cost escalation, allowance for funds during construction (AFDC), owner's costs and owner's contingency funds.

   Since the Control Cost Manual[6] cannot be used for estimating the cost of TESCR and LDSCR because it would underestimate both the capital and annual operating costs, Minnkota has developed a site specific cost estimate with a procedure that varies somewhat from the Control Cost Manual[6]. The Department has reviewed the BART analyses prepared by five different consultants to determine if the listed items were included (Note that BART cost estimates are governed by the same guidance as BACT cost estimates). The five consultants included TRC, BARR Engineering, Co, CH_2M Hill, HDR Engineering, Inc., and Black & Veatch. One of the consultants included startup costs in their estimate for SCR. In addition, the cost estimate sheet in the NSR Manual[4], Appendix B, page b.5 includes startup costs at rate of 2% of the total direct investment (direct capital cost). Minnkota used 2% of direct capital costs. The inclusion of startup costs appears appropriate.

   Cost escalation is driven by general inflation, changes in technology but mostly by supply and demand imbalances for a good or service. To illustrate this point, the consumer price index increased approximately 18% from the beginning of 2003 to the end of 2008. During this same time period, structural steel prices increased (escalated) by over 150%. Escalation is usually included in the contingency funds which can be from 10-25%. However, any estimate for a project in the 2003-2008 time period that used a lot of steel (such as an SCR) may have been underestimated if a 10-25% contingency fund was used. Minnkota has included an escalation cost in their estimate. The estimate is based on 2006 dollars; however, the project would not be completed until 2016-2017. It is unknown whether escalation will be so severe that contingency funds will not cover it. With the implementation of the new Transport Rule and the Regional Haze requirements, the demand for SCRs and the contractors who build these units will greatly increase. Escalation of SCR equipment costs and the erection of such units is likely. Inclusion of some escalation costs, beyond contingency funds, appears to be appropriate.

Allowance for Fund during Construction (AFDC) is for the cost of borrowing money until a project is placed into operation. The review of the BART analyses indicated that one of the five consultants included AFDC as a specific line item for their SCR cost estimate. The Control Cost Manual[6] in Table 2.5 assumes that the AFDC for an SCR is zero. However, there is no explanation for this assumption. An assumption that there will be no interest on money during construction is not credible. In addition to the Control Cost Manual[6], EPA also provides the CUECOST model which can be used for estimating the cost of SCR. This model includes a specific line item for AFDC which has a default value of 10.80% per year. As described earlier, the Control Cost Manual[6] cannot be used for estimating the cost of TESCR and LDSCR. Minnkota has estimated the indirect cost of TESCR and LDSCR consistent with the Cichanowicz[7] document which includes financing during construction or AFDC. Inclusion of AFDC is reasonable.

Owner's costs will consist of, but is not limited to, legal assistance, permitting, owner's project management, owner's site mobilization, O&M staff training, construction insurance, auxiliary power, taxes and consultant fees. Again, one of the five consultants reviewed included a specific line item for owner's costs. One other consultant listed several of the items identified above as owner's costs as separate line items in their estimate. The methodology in Cichanowicz's paper[7] also includes owner's costs. The NSR Manual[4], Appendix B, page b.7 states "Indirect, or "fixed", annual costs are those whose values are relatively independent of the exhaust or material flowrate and, in fact, would be incurred even if the control system were shutdown. They include such categories as overhead, property taxes, insurance and capital recovery." Several items mentioned (i.e. overhead, property taxes and insurance) are owner's costs. The inclusion of owners cost is appropriate and consistent with the NSR Manual.[4]

Minnkota's owners cost includes an owner's contingency amount. The total owner's cost is approximately 17% of the total direct capital cost. Cichanowicz[7] lists a range of owner's cost at 5-10% of the capital cost. The Cichanowicz paper discusses the high rate of increase in the cost of materials and labor. Data is provided to show these increases from 2003 to 2007 including steel, concrete and various labor professions. All of these had escalation rates well above the increase in the consumer price index. It is reasonable to expect that the owner's cost may increase more than the consumer price index. Including escalation for the owner's cost items appears reasonable.

4) EPA believes cost estimations for various items are inflated.

    a) Annual Maintenance Costs – EPA believes a factor 1.5% of total capital investment (as stated in the Cost Control Manual) for annual maintenance costs should be used. Minnkota used 3% for their estimate. Minnkota has argued that additional maintenance will be required for the gas-to-gas heat exchangers

(GGH). Minnkota has also indicated the harsh North Dakota winters will make maintenance more difficult.

The rotary GGHs will provide additional maintenance challenges beyond a normal high dust SCR. Since EPA's 1.5% factor for maintenance is for a high dust SCR, the NDDH believes 3.0% is inappropriate because of the additional equipment that must be maintained. The NDDH also agrees that the harsh North Dakota winters will make maintenance more difficult than an average SCR on which the Control Cost Manual[6] is based. The maintenance factor of 3% appears to be reasonable.

b) Annual Reagent Costs – EPA has argued that anhydrous ammonia would be cheaper. Minnkota has argued that there is no evidence presented by EPA to support their claim that anhydrous ammonia is the cheapest reagent available to MRYS. Minnkota has also argued that health and safety concerns must also be considered.

   EPA provided no evidence to support their claim that anhydrous ammonia delivered to MRYS would be cheaper than urea. The NDDH will not second guess Minnkota when it comes to health and safety matters on the MRYS plant site. The safe handling of anhydrous ammonia during the cold North Dakota winters can present many challenges. The use of urea as the SCR reagent is justified.

c) Annual electricity costs (loss of electrical sales due to extended outages). EPA believes Minnkota's estimate of the time for outages to replace the catalyst is unreasonably high. Minnkota has argued that outages for other reasons (other than catalyst replacement) that are associated with the SCR will occur. This includes forced outages for boiler tube leaks that must be repaired shortly after discovery to prevent severe fouling of a LDSCR. Also, failure of the GGHs will cause additional boiler outage. Forced outages could occur for booster fans and other auxiliary equipment associated with SCR system.

   The NDDH believes it is appropriate to include these other forced outages in the cost estimate for SCR. Failure to recognize that equipment failures/malfunctions other than the catalyst replacement would cause outages would lead to an underestimation of the cost of operating the SCR.

   Minnkota has indicated they used a unit availability reduction of 2.2% associated with the advanced separated overfire air system (ASOFA). These outages could be due to problematic cyclone slag tapping, excessive heat transfer surface fouling, increases in boiler tube leaks and operation of the air-staged cyclone combustion. Prediction of whether the ASOFA system will cause the outage time estimated by Minnkota is extremely difficult. EPA has provided no specific evidence to show that the prediction is incorrect. Without specific evidence to the contrary, the rate is considered reasonable.

d) Catalyst Replacement Costs – EPA has indicated that the replacement cost of catalyst was significantly higher than the bids Minnkota received and substantially higher than Mr. Hartenstein received with his Request for Proposals (RFP).

EPA has not defined what significantly means. A review of the bids indicates virtually no difference to less than a 30% difference. Minnkota has previously indicated they included transportation, handling, storage, installation and taxes in their estimate. Based on the addition of these items, the $7,500/m^3$ used by Minnkota does not appear to be significantly higher for the replacement costs. Regarding the costs Mr. Hartenstein received for his RFP, these costs are considered irrelevant because of the faulty RFP (see Response to Comment IV).

Regarding the use of regenerated replacement catalyst, there is no evidence to prove that catalyst used at the MRYS can be regenerated. This is obvious since it has never been used at MRYS. The flue gas characteristics may preclude the use of regenerated catalyst. Until there is evidence to support the use of regenerated catalyst, Minnkota is justified in providing a catalyst replacement cost based on new catalyst.

e) Use of natural gas for reheating the flue gas - EPA has indicated that it questions whether natural gas needs to be used for reheat instead of steam.

Minnkota has indicated that the units at the MRYS are boiler limited. This is obvious since the changes that lead to the Consent Decree were boiler related and not generator related. Using steam would require the derating of the units (see December 12, 2009 Response to NDDH request). Minnkota has estimated the total derate for MRYS would be 13-16 MWe. Additional arguments against using steam are unsatisfactory results previously using steam for flue gas reheat associated with the Unit 2 scrubber (Minnkota actually abandoned the system and now uses flue gas bypass for reheating), a detailed study is required to determine the performance impacts from the modifications needed to use steam for reheat, and the cost of high pressure steam piping and the structural work needed to handle the thermal growth and load stresses.

The NDDH has discussed the use of steam for reheat with Basin Electric Power Cooperative. Because of the extremely cold North Dakota winters, Basin Electric indicated it was a bad idea because of the potential for problems and the difficulty of fixing those problems in the winter months. The NDDH believes the use of natural gas instead of steam is justified for MRYS.

IV. EPA Corrected Cost Analysis

Comment: EPA has prepared its own cost estimate for LDSCR and TESCR based on the responses to Mr. Hartenstein's RFP and use of the factors in Control Cost Manual.[4] The results show a much lower cost for LDSCR and TESCR.

Response: EPA's cost estimate is based on at least three faulty premises that will affect the cost estimate. These include 1) a faulty RFP by Mr. Hartenstein, 2) Failure to estimate levelized annual cost, and 3) Use of the Control Cost Manual.

The RFP submitted by Mr. Hartenstein was fatally flawed. The RFP flaws include, but are not limited to:

a) The RFP did not mention the fuel was North Dakota lignite.
b) The RFP did not indicate that the sodium in the flue gas was soluble sodium. Soluble sodium is a potent catalyst poison.
c) The concentration of the flue gas constituents (e.g. sodium and potassium) was at the low end of the expected range of these constituents. Both CERAM and Haldor Topsoe have indicated to the Department that the full range of flue gas constituents encountered must be provided to prepare a proper catalyst design. From the data provided, Haldor Topsoe assumed the fuel was eastern bituminous coal.
d) The RFP failed to provide sufficient information on the sticky nature of the ash.
e) The RFP was not sufficiently detailed on particle sizing, particulate concentration and soluble sodium constituents in the flue gas. Both CERAM and Haldor Topsoe have indicated that they would not have provided a catalyst life guarantee to Mr. Hartenstein had the information in his RFP been as detailed as the Minnkota RFP. It is apparent that the catalyst design would also have been different for these vendors.

2) EPA failed to calculate a levelized cost as required by the NSR Manual[4], Appendix B, Section II which states "The permit applicant should use the levelized annual cost approach for consistency in BACT cost analysis."

3) The Control Cost Manual[6] cannot be used for estimating the cost of TESCR and LDSCR (see Response to Comment II.1). The Control Cost Manual states "The cost-estimating methodology, presented here provides a tool to estimate study-level costs for high-dust SCR systems" (emphasis added). Actual selection of the most cost-effective option should be based on a detailed engineering study and cost quotations from the system suppliers. Minnkota has prepared such a cost estimate.

National Parks
Conservation Association
2010 Comments

Comment 1: The NSPS limit of 0.11 lb/10^6 Btu (revised in 2008) should have been considered in the BACT determination.

Response: The limit stated by the commentor is for reconstructed sources. The limit for modified sources is 0.15 lb/10^6 Btu (40 CFR 60.44 Da(e)(3)).

The MRYS is not subject to the NSPS standards for NO_x. The definition of "BACT" indicates the BACT emission limit cannot be any less stringent than an applicable standard under the NSPS. Since there is no applicable standard for MRYS, this portion of the BACT definition is not relevant.

Although EPA has established a limit of 0.15 lb/ 10^6 Btu for all modified coal-fired boilers, there is no evidence to suggest than EPA considered the flue gas characteristics of cyclone boiler combusting North Dakota lignite. EPA cited experience with Gulf Coast lignite, Texas lignite and European brown coals; however, there was no direct discussion of North Dakota lignite (71 FR 9870)[12]. CERAM has indicated there is no experience in the world with the level and form of sodium found in North Dakota lignite[9]. Therefore, EPA's citation to other lignite's is not applicable. EPA then suggested SCR is not required to achieve 0.15 lb/10^6 Btu. This may be true for other pulverized units, but not for cyclone-fired units. Without a detailed evaluation of the flue gas characteristics of a cyclone-fired unit combusting North Dakota lignite, EPA has not demonstrated that the NSPS is achievable for this type of boiler.

Comment 2: The NO_x BACT analysis for MR Young must be considered in the context of the far-reaching impacts of the facility's NO_x emissions on air quality, visibility, public lands and public health under step five of the top-down approach.

Response: North Dakota is in compliance with all of the National Ambient Air Quality Standards. EPA has determined that emissions from North Dakota do no significantly contribute to any non-attainment areas for ozone or $PM_{2.5}$ (75 FR 31290-31306 and 75 FR 45255-45269), The NDDH has evaluated the impact on visibility in the Class I areas if SCR is installed instead of SNCR at MRYS[8]. The improvement in visibility (0.01 deciviews for Unit 1 and 0.02 deciviews for Unit 2 average for the 20% worst days) by using SCR is insignificant. All other impacts are also expected to be insignificant except for the increase in emissions due to using SCR. The SCR will increase CO_2 emissions by 150,000 – 200,000 tons per year due to the need to reheat the flue gas and increased electricity use.

NDDH's Technical Feasbility Analysis is Legally and Technically Deficient

Comment 3: There is no valid technical or other constraints that make SCR installation technically infeasible. A difference in gas stream characteristics does not by itself imply that the difference is significant enough to impact successful operation of the control technology.

Response: Determination of technical feasibility is based on the flue gas characteristics of the source and the potential for successful operation of the control technology evaluated. CERAM Environmental, Inc. has indicated that they are unaware of any SCR experience in the industry with the level and form of sodium in MRYS flue gas[9]. Haldor Topsoe[10] has stated that physical deactivation due to catalyst blinding and plugging could be severe enough to make SCR a non-viable option for controlling NO_x emissions.

These statements indicate there is a significant difference in the flue gas characteristics at MRYS versus other coal and biomass fired boilers that could impact operation of an SCR and technical feasibility. The difference is so great that SCR may not be a workable solution for NO_x control. The lack of vendor guarantees is also strong evidence that SCR is not technically feasible.

Comment 4: Pilot scale testing would not require extended time delays or resource penalties. Pilot scale testing in this case is a means to optimize SCR design to a specific situation prior to more expensive full-scale installation.

Response: CERAM Environmental has indicated that they prefer 5,000 hours of pilot scale testing[9]. Haldor Topsoe has indicated that a 9-12 month pilot scale test is required. Taking into account time to design, fabricate and install the pilot-scale reactor, 5,000 hours of operation, decommissioning and evaluating the data, one to two years would be required for a pilot-scale test. Sargent and Lundy estimated the cost to be 1.5-2 million dollars[13]. This is a significant time delay and cost for MRYS.

Haldor Topsoe has indicated that physical deactivation could be severe enough to make SCR a non-viable option for controlling NO_x emissions[10]. It is clear that pilot-scale testing would be required to prove SCR is a viable option for controlling NO_x emissions and not just for optimizing the design of SCR. CERAM Environmental has pointed out that they are not aware of any SCR experience for flue gas characteristics similar to that at MRYS[9]. Pilot-scale testing would be used to determine if the catalyst deactivation rate is so severe that SCR cannot be successfully applied at MRYS.

Comment 5: To dismiss SCR on the grounds that there is a risk to Minnkota would be contrary to the technology-forcing function of the BACT process that was intended by Congress.

Response: Haldor Topsoe, in a letter to Burns & McDonnell[14], states "HTI does not avoid challenging applications, but we do review the technical as well as the financial risks associated with each project. If the risk level is too high then we may choose not to participate in the project or only provide catalyst without performance guarantees." Haldor Topsoe would not provide a performance guarantee. This indicates the risk of failure of SCR at MRYS is too high for them. This is also apparently true for CERAM Environmental since they refused to provide a guarantee. The NDDH believes the risk of failure is also too high and LDSCR and TESCR are not technically feasible at this time.

NDDH Fails to Accurately Calculate Cost Effectiveness of SCR

Comment 6: NDDH inappropriately compared only regionally - limited BART determinations rather than generally accepted BACT determinations.

Response: The NDDH compared the cost of SCR at MRYS to both BACT and BART analyses. Every BACT determination in the RBLC for the last five years was reviewed and cost data obtained from Missouri, Arkansas, Wyoming and Nevada. These are not regional analyses. BART data was obtained from sources as far as Oregon, Nebraska and Alaska. Again, these are not regional to North Dakota.

Comment 7: A 30-year service life should have been used in the economic analysis.

Response: EPA's Air Pollution Control Cost Manual[6] states that an economic life time of 20 years is assumed for a SCR system (p. 2-48). The Department reviewed several BART analyses which indicated the estimated life of SCR ranged from 11-20 years. Minnkota's use of 20 years is consistent with other economic analysis.

Comment 8: Labor and maintenance costs were estimated at 3% of installed capital costs. The Control Cost Manual indicates they are 1.5% of the total capital investment. Thus these costs are overestimated.

Response: The Cost Control Manual[6] states that it cannot be used to estimate the cost of TESCR. For the same reason (i.e. reheating the flue gas), LDSCR cannot be estimated from the Control Cost Manual. The higher cost used by Minnkota is expected due to maintenance activities that will be more frequent (e.g. catalyst changement) than a typical SCR installation and more difficult because of the cold North Dakota climate. Additional equipment for flue gas reheat will also need maintenance and will increase these costs. The estimate of 3% appears appropriate.

Comment 9: Levelization of costs escalates costs. Cost effectiveness analyses do not include escalation.

Response: Appendix B, Section II of the NSR Manual[4] states "The permit applicant should use the levelized annual cost approach for consistency in BACT cost analysis." The commenter assertion that levelization is not allowed is incorrect.

Comment 10: A cost for catalyst of $7,500 per cubic meter is excessive and catalyst regeneration must be considered.

Response: The cost of the catalyst quoted in the Confidential Vendor Proposals is substantially higher than $3,500/m^3$. Minnkota has added shipping, handling, storage, labor, mobilization, disposal costs and taxes to the cost of the catalyst. Based on the vendor proposals, $7,500/m^3$ is reasonable.

Catalyst regeneration has not been demonstrated for a catalyst exposed to flue gas characteristics similar to the MRYS. Therefore, the cost of regenerated catalyst in the cost estimate is inappropriate.

Comment 11: The costs for foundations and supports needs to be justified.

Response: The costs of foundations are directly affected by the soil type encountered at the specific site. Minnkota has provided a site specific analysis for foundations and supports. A site specific estimate is preferred to a general estimate.

Comment 12: The indirect costs include owner's costs which are not included in the Control Cost Manual.

Response: The Control Cost Manual cannot be used for estimating the cost of TESCR or LDSCR (see Response to Comment 8). Minnkota has used a cost estimating methodology which is consistent with those by Cichanowicz[7]. This methodology includes owner's cost at a rate of 5-10%. (Also see Response to EPA 2010 Comment III).

Comment 13: The commenter had concerns about the costs associated with electrical equipment, SCR installation and maintenance, contingency expenses and capital cost of the SCR system and auxiliaries.

Response: The commentor provided no details or examples to support his concerns. Since there are no details, a detailed response cannot be made. The NDDH believes Minnkota's estimate is within the required range of ± 30%.

Comment 14: Several states have established cost effectiveness thresholds based on pollutant controlled, not bound by the emitting source categories.

Response: The NSR Manual, Section IV.D.2. C., states "In essence, if the cost of reducing emissions with the top control alternative, expressed in dollars per ton, is on the same order as the cost previously borne by other sources of the same source category in applying that control alternative, the alternative should initially be considered economically achievable, and therefore acceptable as BACT" (emphasis added). The NSR Manual[4] also discusses this issue further and terminology specific to "that source category" and for "the type of facility". It is clear that a comparison must be made for the source category reviewed, not dissimilar source types. Cost comparisons must also be made to costs borne by the same source category. Guidance from other states is irrelevant until applied to a source similar to MRYS that actually bears that cost.

Comment 15: U.S. EPA determined that $10,000/ton control cost ceiling was for NO_x and SO_2 in attainment areas, equivalent to over $13,000/ton today.

Response: The EPA document referenced by the commenter addresses costs at refineries and is listed as an upper bound. The NSR Manual[4], Section IV.D.2.(p.B-32) states "To justify elimination of an alternative on these grounds, the applicant should demonstrate to the satisfaction of the permitting agency that costs of pollutant removal for the control alternative are disproportionally high when compared to the cost of control for that particular pollutant and source in recent BACT determinations" (emphasis added).

The NDDH is not aware of EPA ever establishing a brightline cost effectiveness cutoff for BACT. As noted in the NSR Manual, any cutoff would be established by recent BACT determinations and costs actually borne by similar sources.

Comment 16: Several air districts in California have set cost effectiveness thresholds for NO_x including \$9,700/ton, \$17,000/ton and \$17,500/ton.

Response: See response to Comments 14 and 15. The San Joaquin Valley District noted that their definition of BACT is the most stringent limitation or control technology that is:

- Achieved in practice by such a source category and Class of source
- Required by the SIP.

The most stringent limitation that is achieved in practice is considered to be LAER (lowest achievable emission rate) in most of the United States. LAER is not the same as BACT in North Dakota.

Most of California is nonattainment for ozone. Controlling NO_x emissions is vital to achieving or maintaining compliance with the ozone NAAQS. Therefore, California has very stringent emission limits for NO_x in their SIP that may be more stringent than BACT elsewhere. This can be seen from the BACT guidance for the San Joaquin Air District which lists a BACT cost effectiveness for SO_2 at \$3,900/ton.

Guidance documents do not meet the requirement to compare costs at the source under review to recent BACT determinations. The NDDH does not consider \$9,700 - 17,500/ton to be cost effective for NO_x controls in North Dakota.

Comment 17: The commentor provided data on several determinations which he indicates show BACT costs well over that estimated at MRYS.

Response: Of all the summaries provided, only one BACT determination was for a coal-fired power plant. The rest were gas turbines, refineries, cement plants or other types of sources. As indicated in the Response to Comments 14 and 15, costs must be compared to recent BACT determinations for the same source category.

The Weston Power Plant BACT determination was reviewed. When an apples-to-apples comparison in done, the BACT cost of SCR at the Western Plant is actually considerably lower than at MRYS (see Response to EPA's 2010 Comment 7).

Comment 18: The BACT analysis gave undue influence to the incremental cost.

Response: The NSR Manual[4], Section IV.D.2.b, states "the cost-effectiveness calculations can be conducted on an average, or incremental basis." It also states "The incremental cost should be examined in combination with the average cost effectiveness in order to justify elimination of a control plan." The NDDH provided both the cost effectiveness and the incremental cost for the two dominant control operations. The cost effectiveness of SCR is considered high and the incremental cost between SNCR and SCR is considered very high. Other BACT determinations have rejected control options based on incremental cost where the cost effectiveness was much lower than at MRYS including:

Facility	Cost Effectiveness ($/ton)	State
Longleaf Generating Station (SO_2)	724	GA
Hardin Plant (SO_2)	1,395	MT
Red Trail Energy (NO_x)	2,609	ND
Intermountain Power (PM_{10})	≈37	UT
Dry Fork (NO_x @ 0.040)	2,004	WY
Dry Fork (SO_2 – WFGD)	1,595	WY
WYGEN Z (NO_x @ 0.060)	4,156	WY
WYGEN 3 (PM_{10})	134	WY

Minnkota's estimate of cost effectiveness for LDSCR/TESCR ranged from $3,586/ton to $6,426/ton.

The NDDH considered the cost effectiveness of SCR, the incremental cost between SCR and SNCR, the additional pollutants emitted by using SCR and the uncertainty regarding the technical feasibility of SCR. When all factors are considered together, SNCR is BACT.

National Park Services
Comments
2010

Comment 1: NDDH errored by using historical emissions for baseline emissions.

Response: The NSR Manual[4], Section IV.D.2.b, states "In addition, historic upper bound operating data, typical for the source or industry, may be used in defining baseline emissions in evaluating the cost effectiveness of a control option for a specific source" (emphasis added). Minnkota calculated baseline emissions based on a maximum emission rate and maximum expected utilization. The historical data for these specific units suggests a lower baseline than calculated from maximum values. The Department's approach is consistent with the NSR Manual.

Comment 2: Minnkota incorrectly included major costs for "allowance for Funds During Construction, Escalation, Owner's Cost and a levelization factor which are not allowed by the cost manual."

Response: The Control Cost Manual[6] cannot be used for estimating the cost of TESCR or LDSCR because it does not account for reheat of the flue gas. Minnkota has provided a site specific cost analysis. Minnkota used a procedure similar to that outlined in the paper Current Capital Cost and Cost Effectiveness of Power Plant Emissions Control Technologies[7] by Cichanowicz. This methodology includes an Owner's Cost and Financing during construction. The NSR Manual[4], Appendix B, Section II, states "The permit applicant should use the levelized annual cost approach for consistency in BACT cost analyses". Therefore, levelized cost approach with an escalation factor is appropriate (See Response to EPA's 2010 Comment III).

Comment 3: The commentor provided his estimate of the cost of TESCR and ASOFA for both units of MRYS using the Control Cost Manual[6].

Response: As indicated in Section 2.4 (p2-41) of the Control Cost Manual, the cost of TESCR cannot be estimated from the document because the costs are significantly higher than high dust SCR systems due to flue gas reheating requirements. Therefore, the cost estimate supplied by the commenter is inappropriate, especially for O&M costs.

The NDDH also believes that Control Cost Manual is extremely out-of-date for such cost estimates. The costs presented are in 1998 dollars (Section 2.4, p. 2-40). ERG, Inc. evaluated the cost of SCR for PGE Boardman plant as part of BART determination. ERG[10] has indicated that SCR installed costs have escalated rapidly since 2004 (p.4). The commentor also used an inappropriately high baseline emission rate that has never been achieved in the history of the facility. Continuous emission monitoring data indicates the maximum annual emission rate for Unit 1 was 9,220 tons/yr (2 year average of 8,840 tons/yr). The maximum single year for Unit 2 was 17,727 tons (2 year average of 15,507 tons/hr). The commentor baseline is 31% higher than the historical highest single year for Unit 1 and 34% higher than the historical highest year for Unit 2. The underestimating of the O&M costs and the inappropriate baseline emission rate lead to an underestimate of the costs effectiveness of TESCR + ASOFA.

Comment 4: The Wyoming DEQ has determined that incremental costs of $10,303 and $11,102 respectively were reasonable.

Response: While Wyoming may have determined that an incremental cost of up to $11,102 per ton is acceptable, other states such as Georgia, Nebraska, Pennsylvania, the U.S. EPA Region 8 and North Dakota have determined that it is not reasonable.

Comment 5: The NDDH should have primarily considered sources where SCR was accepted as BART.

Response: The NDDH provided the cost data from BART analysis for comparison purposes. A BART determination must take into account the amount of visibility improvement, a BACT determination does not. Each state is free to weigh the visibility impact factor as much as they choose. Some states may give great weight to visibility improvement with little weight to cost. Other states may be vice versa. Therefore, a BART determination cannot be compared to a BACT determination. However, the cost effectiveness can be compared and indicate that the cost of SCR at MRYS is at the high end of the cost scale.

Comment 6: The NDDH used a heat input of 3200 x 10^6 Btu/hr, 100% utilization and 0.86 lb/10^6 Btu, in conducting its BART analysis for Unit 1. Absent any constraints in a permit, those values should also be used for the BACT analysis which yields an NO_x emission rate of 12,054 tons per year for the uncontrolled situation.

Response: The commenter is incorrect. In its BART evaluation for Unit 1, the NDDH used a baseline emission rate of 9032 tons per year. This is very similar to the BACT analysis which used 8518 tons/per year. As noted in the response to Comment 3, the maximum measured annual emission rate was 9220 tons per year in 2001. Emissions have decreased steadily since then. The difference between the BART baseline is due to the review of two different five-year periods for this unit, one for BART and a more recent one for BACT. Use of 3200 x 10^6 Btu/hr, 100% utilization and an emission rate of 0.86 lb/10^6 Btu does not represent realistic upper bound operating conditions for this unit as required by the NSR Manual[4].

Comment 7: In the absence of permit constraints, the baseline emissions should be based on a heat input of 6300 x 10^6 Btu/hr, 100% utilization and an emission rate of 0.86 lb/10^6 Btu which yields an uncontrolled emission rate of 23,271 tons per year. This operating data was used in the BART analysis.

Response: The commenter is incorrect. In its BART determination, the NDDH used a baseline emission rate of 15,507 tons per year. This is similar to the 14,858 tons per year baseline used in the BACT analyses. As noted in the response to Comment 3, the maximum measured emission rate is 17,727 tons per year in 2000 and emissions have been decreasing since then. Use of the suggested operating parameters for determining baseline emissions for Unit 2 does not represent realistic upper bound conditions for Unit 2.

Comment 8: The commentor provided his estimate of costs for Unit 1 and Unit 2 TESCR with his assumptions. These are located in Appendix B and are based on the OAQPS Manual[6].

Response: The Cost Control Manual[6] cannot be used for estimating the cost of TESCR (see SCR Section 2.4, p.2-40). With respect to the commenter's assumptions:

a) Catalyst Cost = $3,000/m^3$ – The confidential proposals submitted by vendors have a much higher catalyst cost. Based on this vendor's proposals, the $7,500/m^3$ appears to be reasonable when shipping, handling, storage, installation and disposal costs are included.

b) Operating Life of Catalyst = 16,000 hours – No vendor has provided a guarantee for the life of the catalyst. Pilot scale testing will be required to determine an appropriate life of the catalyst. Using 16,000 hours is speculation and may significantly overestimate the life and underestimate the operation and maintenance costs.

c) Natural Gas = $5/mcf – The EIA "has estimated that he cost of natural gas for commercial operations will vary from $8.92 - $12.12 per decatherm for the period 2010 – 2030. The cost for industrial sources is from $5.02 - $8.21 per decatherm. For a levelized annual cost analysis, as required by the NSR Manual[4], a cost of $5 per decatherm is too low. Minnkota used $8 per decatherm which appears to be reasonable.

d) Baseline Emission Based on 100% Utilization – See Response to Comments 1, 6 and 7.

e) Escalation and Owner's Costs are not allowed – See Response to Comment 2.

Basin Electric Power Cooperative
Comments
2010

Comment 1: Basin Electric supports the conclusion that SCR does not represent BACT for the MRYS. This is based on their own investigation of SCR for Leland Olds Unit 2 which indicated extensive pilot scale testing was necessary to predict the performance of SCR on a cyclone boiler firing North Dakota lignite. Basin Electric found it particularly significant that two vendors that had previously indicated they would provide a guarantee for a boiler firing North Dakota lignite now refuse to provide such a guarantee for LDSCR and TESCR at MRYS.

Response: No response necessary

Ottertail Power Company
Comments
2010

Comment 1: Ottertail supports the conclusion that SCR does not represent BACT for the MRYS.

Response: No response necessary

Environmental Groups

Comment I: NDDH consistently misapplies the "technically feasible" analysis set forth in the NSR Manual and thus, the review of the BACT analysis is flawed.

Response: The NSR Manual, Section IV.A, Step 1, states:

"The top-down BACT analysis should consider potentially applicable control techniques from all three categories. Lower-polluting processes should be considered based on demonstrations made on the basis of manufacturing identical or similar products from identical or similar raw materials or fuels. <u>Add-on controls, on the other hand, should be considered based on the physical and chemical characteristics of the pollutant-bearing emission stream. Thus, candidate add-on controls may have been applied to a broad range of emission unit types that are similar, insofar as emissions characteristics, to the emission unit undergoing BACT review</u>" (emphasis added).

The NSR Manual, Section IV.B, Step 2, states:

"Within the context of the top-down procedure, an applicant addresses the issue of technical feasibility in asserting that a control option identified in Step 1 is technically infeasible. In this instance, the application should make a factual demonstration of infeasibility based on commercial unavailability and/or unusual circumstances which exist with application of the control to the applicant's emission units. Generally, such a demonstration would involve an evaluation of the pollutant-bearing gas stream characteristics and the capabilities of the technology. Also a showing of unresolvable technical difficulty with applying the control would constitute a showing of technical infeasibility (e.g., size of the unit, location of the proposed site, and operating problems related to specific circumstances of the source). Where the resolution of technical difficulties is a matter of cost, the applicant should consider the technology as technically feasible. The economic feasibility of a control alternative is reviewed in the economic impacts portion of the BACT selection process.

A demonstration of technical infeasibility is based on a technical assessment considering physical, chemical and engineering principles and/or empirical data showing that the technology would not work on the emissions unit under review, or that unresolvable technical difficulties would preclude the successful deployment of the technique."

The Department has evaluated the pollutant bearing gas stream of the M.R. Young Station (MRYS) and compared it to other power plant gas streams where SCR has been successfully applied. The results indicate the sodium concentration in the flue gas would be at least 9 times higher in the MRYS flue gas than other cyclone boilers. In addition, the sodium is in a soluble form. The soluble form of sodium is a potent catalyst poison and can cause plugging and blinding of the catalyst. For the four main catalyst poisons, the MRYS flue gas would contain approximately twice as much of these poisons as Texas lignite or Wyoming subbituminous coal-fired units.

As stated in the NSR Manual (Section IV.B):

"Commercial availability by itself, however, is not necessarily sufficient basis for concluding a technology to be applicable and therefore technically feasible. Technical feasibility, as determined in Step 2, also means a control option may reasonably be deployed on or "applicable" to the source type under consideration (emphasis added).

Technical judgment on the part of the applicant and the review authority is to be exercised in determining whether a control alternative is applicable to the source type under consideration. In general, a commercially available control option will be presumed applicable if it has been or is soon to be deployed (e.g., is specified in a permit) on the same or a similar source type. Absent a showing of this type, technical feasibility would be based on examination of the physical and chemical characteristics of the pollutant-bearing gas stream and comparison to the gas stream characteristics of the source types to which the technology had been applied previously. Deployment of the control technology on an existing source with similar gas stream characteristics is generally sufficient basis for concluding technical feasibility barring a demonstration to the contrary" (emphasis added).

Although SCR has been applied to various coal-fired boilers, the Department has found no evidence that SCR has been applied to a flue gas with as high a sodium (Na) concentration as the MRYS flue gas. CERAM Environmental has indicated they are not aware of any SCR application experience in the industry with the level and form of sodium in the M.R. Young Station ash. EPA's consultant, Mr. Roger Christman from ERG, Inc., indicated he was not aware of any facility with this high of sodium loading where SCR had been applied. This confirms the flue gas characteristics are dissimilar from other sources where the technology has been applied. Because the sodium in the flue gas is a catalyst poison and can cause plugging and blinding of the catalyst, the Department believes currently available catalysts for an SCR system may not be successful when applied to the MRYS flue gas. As explained in the Department's June 2008 "Preliminary Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2" (hereafter preliminary determination), successful application of SCR technology does not mean operation of the system for a few thousand hours before changeout of the catalyst. The Department established a minimum of 10,000 hours between changeouts before SCR can be determined to be "successfully applied" to MRYS. There is very little evidence to support the thought that available catalysts will last at least 10,000 hours before the BACT limit is exceeded or ammonia slip becomes excessive. Haldor Topsoe has stated that the potential exists that physical deactivation due to catalyst blinding and plugging could be severe enough to make SCR a nonviable option for controlling NO_x emissions. Pilot testing is required to determine whether SCR technology is a viable option to control NO_x emissions, establish design parameters for an SCR system and to determine the catalyst life. Both Haldor Topsoe and CERAM have offered catalyst life guarantees for Texas lignite, European brown coals and biomass; yet, both have refused to offer a guarantee for North Dakota lignite at MRYS. Therefore, existing SCR technology is not available or applicable for the MRYS.

Comment II: NDDH and Minnkota have not adequately supported the decision to disregard fuel switching/blending as technically feasible.

A. Lack of railroad access to M.R. Young does not make fuel switching/blending infeasible.

Response: The Department did not say that the lack of railroad access made fuel switching/blending infeasible. This fact was pointed out to show the changes that would be necessary to bring in other types of coal. In fact, the Department pointed out that burning PRB coal is technically feasible (see p. 14 of preliminary determination). The trucking of PRB coal to blend with Center lignite would be extremely expensive and as pointed out have no effect on emissions (see discussion under Response to Comment 2.B and 2.C).

B. Using the annual average NO_x emission rate is not acceptable for labeling fuel switching/blending as technically infeasible.

Response: The Department did not say fuel switching was infeasible (see p. 14 of the preliminary determination). The Department compared the annual average emission rate of the Big Stone Station in South Dakota to that of the MRYS. The Big Stone Station is equipped with a cyclone boiler of similar design to MRYS and was originally designed to burn lignite from the Peerless Mine near Gascoyne, North Dakota. Since the Big Stone boiler is of similar design, a comparison of annual average uncontrolled emission rates provides a legitimate comparison of very similar units, one burning subbituminous coal and the other burning lignite. Based on the design, the 30-day rolling averages are expected to be proportional to the annual averages.

The use of the Acid Rain database as a whole for comparison, as suggested by the commentors, is clearly erroneous. The database contains units that are not cyclone units (higher emitters) and includes sources which have NO_x controls installed. A legitimate estimate of the effect of PRB on NO_x emissions must be made considering only cyclone boilers without NO_x controls.

C. The combustion of PRB would result in lower NO_x emissions.

Response: Based on actual operating data from the Big Stone Station, burning of PRB alone would not lower uncontrolled emissions of NO_x and may actually increase emissions on a $lb/10^6$ Btu basis. Blending even 50% PRB with lignite would only reduce the amount of sodium in the MRYS flue gas by a factor of 2. It would still be 4-5 times more than a cyclone burning PRB. This still would make SCR infeasible. Only a near total switch to PRB would make SCR feasible.

The commentor tries to use AP-42 emission factors to establish that Montana PRB would provide lower baseline uncontrolled emission rates. However, actual continuous emissions monitoring data from Big Stone and MRYS show that subbituminous coal would have higher emissions on a $lb/10^6$ Btu basis. AP-42, Introduction, Figure 1 shows that CEM data is the most reliable data available. The CEMs at Big Stone and MRYS are all certified to their accuracy under the Acid Rain Program. The data has been checked and quality assured before being entered into EPA Acid Rain database. AP-42 states "Average emission factors differ significantly from source-to-source and, therefore, emission factors do not provide adequate estimates of the average emission rate for a specific source. The extent of between-source variability that exists, even among similar individual sources, can be large depending on process, control systems, and pollutants." This can be seen by calculating the emission rates using the AP-42 emission factors and comparing them to the emission rates measured by the CEMs. AP-42 would predict an emission rate of approximately 1.05 lb/10^6 Btu for a cyclone boiler burning PRB coal and 1.13 lb/10^6 Btu for a cyclone boiler burning lignite. However, actual CEM data for Big Stone and MRYS show emission rates of 0.83 lb/10^6 Btu, 0.85 lb/10^6 Btu and 0.79 lb/10^6 Btu (2 units at MRYS). EPA, in AP-42 cautions "Data from source-specific emissions tests or continuous emissions monitors are usually preferred for estimating a source's emissions because those data provide the best representation of the tested source's emissions." AP-42, in this case, is inaccurate for both Big Stone and MRYS.

Comment III: The BACT Determination does not adhere to the guidelines set forth in the Consent Decree.

Response: The Consent Decree states that the BACT determination must be "in accordance with applicable federal and state statutes, regulations, and guidance." The commentors claims that Sierra Club, et al. v. U.S. Environmental Protection Agency and Prairie State Generating Company LLC (hereafter Prairie State) cannot be applied retroactively and should be interpreted very narrowly. The decision in Prairie State is simply an interpretation of existing statute, regulations and guidance. The decision clarifies the issue of redesigning a plant which EPA has not required as part of the BACT determination. Since EPA, historically, has not required the redesign of source, any further interpretation of EPA guidance should be available to Minnkota.

The changes necessary at Prairie State Generating are described in the following: "But to convert the design from that of a mine-mouth plant to one that burned coal obtained from a distance would require that the plant undergo significant modification - concretely, the half-mile long conveyor belt, and its interface with the mine and the plant, would be superfluous and instead there would have to be a railspur and facilities for unloading coal from rail cars and feeding it into the plant." These are the same changes Minnkota would have to make to MRYS. MRYS was designed and has operated as a mine-mouth power plant for 40 years using only coal from BNI's Center Mine. Switching from Center Mine lignite to rail car delivered coal would make the existing truck delivery, crushers, conveyors and stackers superfluous. Minnkota would have to not only build a railroad spur but also approximately 10 miles of track. In addition, a railcar unloading facility and a transport system to get the coal to boilers would have to be built. Minnkota would not only have to redesign an existing facility but would have to also reconstruct it. The required actions at MRYS are almost identical to those at Prairie State Generating; therefore, the decision should be applied to MRYS.

Comment IV: Other reviewing authorities, including EPA and the Texas Commission on Environmental Quality, have found SCR to be technically feasible for lignite.

Response: There has never been a BACT determination for a cyclone boiler that combusts North Dakota lignite made either by the Department or EPA. Texas lignite does not have similar flue gas characteristics to North Dakota lignite when considering the application of SCR. As shown in the Department's preliminary determination (see p. 21-27), ash from Texas lignite is much lower in sodium and other catalyst deactivating chemicals. A determination of both availability and applicability are based on the flue gas characteristics of the source under review. Both CERAM and Haldor Topsoe have offered catalyst life guarantees for facilities that combust Texas lignite; however, they have refused to offer a guarantee for the MRYS. Any comparison on Texas lignite to North Dakota lignite for SCR is inappropriate and any BACT determinations for Texas lignite are irrelevant.

The State of Louisiana recently (5/28/08) determined that SCR was technically infeasible for an activated carbon plant that utilizes lignite. This determination indicated the flue gas characteristics of lignite would preclude the successful application of the technology.

Comment VI: NDDH and Minnkota have not considered engineering solutions that facilitate the use of SCR, rendering the BACT top-down analysis complete.

1. Fuel blending/switching in conjunction with SCR.

Response: This issue is addressed in the response to Comments II and III .

2. Injection of fluxing agent to increase melting of the solid combustion byproducts, creating less flyash to be portioned and reinjected into the exhaust gas to poison the catalysts.

Response: The use of fluxing agents would not prevent the melting of sodium particles that are carried in the flue gas, it may actually enhance it. The sodium becomes a fume which is not captured in the slag. Sodium is the main cause of catalyst deactivation and fluxing agents will not reduce the amount of sodium reaching the catalyst of an SCR system.

3. Sootblowing and screens to minimize fly ash and prevent plugging of catalysts.

Response: Sootblowing may remove surface deposits of ash; however, it will not remove the sticky sodium and potassium deposits that penetrate into the pores of the catalyst and cause deactivation. Screens are effective in removing larger ash particles such as popcorn ash but will be ineffective in removing the submicron sodium and potassium aerosols.

4. Catalyst improvement by surface and edge coating . . .

Response: Edge coating of the catalyst may reduce erosion, however, it will not reduce catalyst deactivation or channel plugging. The testing that was conducted in Florida appears to be at a plant that fired PRB subbituminous coal. PRB coal is much lower in sodium and other catalyst deactivation substances (Na_2O, K_2O, etc.). The results of that testing would not be directly applicable to a unit burning North Dakota lignite. Additional pilot testing would be necessary to determine if the surface coating was effective in reducing the deactivation rate for North Dakota lignite.

5. Conventional Coal Cleaning - Wet process

Response: While conventional coal cleaning will remove ash, sulfur and perhaps mercury, there is no evidence supplied to indicate that conventional coal cleaning will remove the organically associated sodium or other catalyst poisons in North Dakota lignite. Pilot testing would be required to determine if this technology would be effective.

6. Coal Cleaning and Drying

Response: Coal drying is already in use at MRYS. MRYS is equipped with a cyclone drying system. Removing moisture from the coal does not remove the sodium, potassium and other deactivation substances. Coal cleaning using air jigs will have little effect on these substances. The results of testing coal drying at the Coal Creek Station suggest only a 2.8 to 5% reduction in heat input rate. This would be insufficient to offset the sodium in the coal which is 275-1400%+ more than other coals. The Department has addressed K-fuels® in the preliminary determination. K-fuels® has been recently rejected as BACT for four other projects that burn lignite[15]. There is no additional evidence supplied by the commentor that K-fuels® would be appropriate as BACT.

7. Coal Beneficiation - Coal Creek

Response: The effect of the coal beneficiation systems developed at the Coal Creek Station on SCR catalyst deactivation substances has not been demonstrated. The 2.8-5% heat input reduction rate from the drying process would have only a minor effect, if any, on the catalyst deactivation rate. The air jigging process will not remove the chemically bound sodium in the lignite.

Comment VI: NDDH has not reviewed add-on controls nor a combination of controls that may overcome the challenges associated using SCR and have proved more efficient reduction of NO_x than SNCR.

1. Deep Staging - Rich Reagent Injection - SNCR system or Advanced Layered Technology Approach (ALTA)

Response: This technology has been addressed extensively by Minnkota (Appendix A, Sections A.1.3.3, A.1.4.1.2 and A.1.4.1.3). There are insurmountable problems in controlling the air/fuel mixture at each cyclone so that an area devoid of oxygen is established for Rich Reagent Injection (RRI) to work properly. Because of the variability of the fuel, some cyclones may be devoid of oxygen while others will have surplus oxygen. This surplus oxygen will oxidize the urea from the RRI process and form more NO_x.

2. Deep Staging - Overfire Air (OFA) - Continuous Corrosion Monitoring, Combustion Control - Oxygen Injection

Response: The information about this technology appears to be taken from a Power Engineering article from November 2006. The article indicates the technology is only in the pilot scale testing phase and no results from the testing are available. The testing is being conducted on high-volatile bituminous coal. Since this technology is only in the pilot scale phase of development and has only been tested on high-volatile bituminous coal, it is not considered available for lignite applications.

3. Gas Reburning with Low NO_x Burners

Response: The testing at Wisconsin Power and Light's Nelson Dewey Plant was with coal reburning only. There were no low NO_x burners as implied by the comment. The test was conducted on subbituminous and bituminous coal. Minnkota has addressed this testing in their BACT assessment (Appendix A, Sections A.1.2.7.2 and 1.2.7.3). The tests using low NO_x burners occurred at Cherokee Station in Colorado which are not cyclone fired units. Lignite (coal) reburn with advanced separated overfire air (ASOFA) was considered as a technically feasible option. Low NO_x burners are not applicable to a cyclone fired unit.

4. Amine-Enhanced Gas Injection (AEGI)

Response:

AEGI is a category of NO_x controls including Amine Enhanced Fuel Lean Gas Reburn (AEFLGR) which has been installed at Public Service Electric and Gas Mercer Station in New Jersey. Minnkota addressed this technology (Appendix A, Section A.1.4.2.1). The commentor suggests that this technology was eliminated without an analysis of the flue gas characteristics. FLGR is a "process-type control alternative" since it prevents the formation of NO_x rather than removing it after the NO_x is formed. The NSR Manual states "For process-type control alternatives the decision of whether or not it is applicable to the source in question would have to be based on an assessment of the similarities and differences between the proposed source and other sources to which the process technique has been applied previously." Since it has not been demonstrated on or applied to a cyclone boiler, its effectiveness has not been demonstrated. FLGR plus SNCR was eliminated based on that analysis and because it provided less NO_x reduction than ASOFA + SNCR. The commentor has provided no evidence to dispute those findings.

5. Flue Gas Recirculation (FGR)

Response: FGR was addressed by Minnkota in their BACT assessment (Appendix A, Section A.1.2.5). The commentor claims that the Department inappropriately dismissed this methodology based on the premise that it would be ineffective in reducing NO_x emissions. MRYS Unit 1 was originally equipped with FGR but it was ultimately removed. Initial stack testing at MRYS Unit 1 shortly after startup indicated NO_x emission rates of 0.91-1.09 lb/10^6 Btu. The current baseline emission rate is 0.85 lb/10^6 Btu (annual average). Adjusting the baseline emission rate to a short-term average as measured by stack testing would yield comparable emission rates. Based on actual operating data, FGR has not and probably will not reduce NO_x emissions at Unit 1. Unit 2 is equipped with FGR.

6. Hybrid Selective Reduction

Response: The commentor is apparently referring to an SNCR/SCR hybrid system. This technology was not considered because SCR was considered to be technically infeasible. This technology would be no more effective than SNCR since SCR is infeasible. Therefore, it is an inferior option that is technically infeasible.

7. Oxyfuels or Oxygen Enhanced Combustion

Response: Minnkota addressed oxygen-enhanced combustion (Appendix A, Section A.1.2.4). The Department addressed it on p. 60 of the preliminary determination. This technology was eliminated because it was determined to be inferior to other control techniques. The commentor has provided no evidence to dispute that assertion.

8. Regenerative Activated Coke Technology (ReACT)

Response: The Regenerative Activated Coke Technology (ReACT) is an integrated emissions control technology intended for installation downstream of a particulate control device. The process consists of an absorber, regenerator and product recovery. The process is capable of removing sulfur dioxide, nitrogen oxides, mercury and particulate matter. The process has been available in Germany and Japan; however, it has only recently been tested on U.S. bituminous and subbituminous coals. The testing was conducted at the Valmy Generating Station in northern Nevada in 2007. A paper titled "ReACT Process Demonstration at Valmy Generating Station" (Dene, C.; Gilbert, J.; Jackson, K. and Miyagawa, S.) presented the results of the testing. For NO_x, the testing indicated a removal efficiency of 38.35 to 40.6 percent. The paper also presents data from testing at the Isogo #1 boiler in Japan. Those results indicate a 10-50 percent removal efficiency.

The ReACT process has not been tested on a North Dakota lignite-fired boiler. The amount of NO_x removal for lignite is unknown; however, the Valmy and Isogo #1 testing indicates the technology would be inferior to ASOFA plus SNCR (10-50% versus 58%). Only pilot scale testing will indicate whether this technology can be successfully applied to a unit firing North Dakota lignite. Since it is an inferior option and is considered unavailable, it is not considered further in the BACT determination.

9. Chemical Oxidation/Chemical Reduction

Response: Although these systems were not evaluated by Minnkota, they were evaluated at the Coal Creek Station and Stanton Station as part of the Regional Haze BART program and at the Spiritwood Generating Station as part of a BACT assessment[15]. At Coal Creek the cost effectiveness was $11,610/ton, at Stanton was $23,217/ton and Spiritwood Generating Station it was $6,534/ton. Each of these analyses showed the cost was excessive especially when compared to other technology including SNCR. Non-air quality concerns with this technology include high electricity consumption and the production of nitrates in the FGD waste product. The production of nitrates may require a wastewater treatment system. In addition to the environmental and energy impacts, there is very limited operating experience for this technology. The $LoTo_x$ technology has only been demonstrated at industrial plants with small boilers compared to MRYS boilers. Whether this technology can be adapted to large power plants would require extensive testing. Based on the high cost, energy and adverse environmental impacts, and the limited application of the technology, the Department eliminates this technology from consideration.

10. Mitsui Babcock (now Doosan Babcock Energy) NO_x Star™

Response: This technology was evaluated by Minnkota (Appendix A, Section A.1.3.2) and by the Department (p. 61 of preliminary determination). The commentor provided no evidence disputing the findings of the Department.

11. Mitsui Babcock Combined Non-Catalytic NO_x Reduction System

Response: This technology combines SNCR, low-NO_x burners, deep furnace staging, boosted overfire air, and coal and gas reburn. All of these technologies have been addressed separately or in some combination by Minnkota. Low NO_x burners are not installed on cyclone fired boilers and are technically infeasible. Therefore, the Mitsui Babcock CNCR system, which relies on low NO_x burners in combination with all of the other technologies in the control system, must also be deemed technically infeasible.

12. RJM Layered System

Response: The RJM layered system consists of burner modification, overfire air, NO_x (combustion) tempering, SNCR, and the RJM-AC™ system. Combustion tempering was evaluated by Minnkota (Appendix A, Section A.1.2.6) and it was concluded that water injection would be difficult for lignite-fired cyclone boilers due to the high moisture content of lignite and the need to readily ignite and sustain combustion and molten slag formation in the cyclone furnaces. The technology was deemed technically infeasible. The RJM-AC™ system is based on Rich Reagent Injection (RRI) technology. Minnkota evaluated RRI (Appendix A, Section A.1.3.3) and determined it was technically infeasible due to the variable heat content of the lignite combusted which creates the inability to control the oxygen levels to near zero at the reagent injection point.

Since two of the RJM-LT layers are technically infeasible for MRYS, the entire technology must be deemed technically infeasible. The combustion modifications, overfire air and SCNR layers of RJM-LT have been proposed as BACT.

Comment VII: The startup and shutdown (SU/SD) periods at Minnkota are excessive and do not reflect the reported plant design at Minnkota.

Response: Minnkota has established the length of startups and shutdowns based on actual operating data. The length of time for unit startup or shutdown is irrelevant to the BACT limit established for such periods. The limit is written as a lb/hr limit on a 24-hour rolling average. The BACT determination does include a definition for startup as suggested by the commentor. The definition of startup includes a heat input level as a cut-off for startup which is directly proportional to the output level as suggested by the commentor. In addition, the BACT limited startup to a maximum of 61 hours for Unit 1 and 115 hours for Unit 2. Minnkota has indicated the Smart Process will be installed on Unit 2, although it does not affect the length of startup or shutdown.

Comment VIII: The exclusion of SU/SD from the "30-day rolling average" and establishment of a separate SU/SD limit violates the Consent Decree.

Response: The Department agrees that shutdowns cannot be excluded from the 30-day rolling average and the BACT determination will be adjusted accordingly. However, the Consent Decree states in Paragraph 66 "NDDH's BACT Determination shall also address specific NO_x emission limitations during Unit Startups." The separate limits for startup and exclusion from the 30-day rolling average are appropriate.

Comment IX: The Control Efficiency proposed by NDDH and Minnkota does not represent BACT.

Response: The removal efficiency required by Minnkota is 58% for both units, not 41% as stated by the commentor (p. 63 of preliminary determination). The discussion from p. 66 to p. 68 pertains to startup and shutdown of the boiler, not normal operation. This pertains to the use of SNCR, not SCR as the commentor implies. The temperature range of NO_x reduction with ammonia and urea is for SNCR which does not use a catalyst as with SCR. Because SCR uses a catalyst, lower temperatures provide optimum NO_x reduction. When a boiler is starting up and shutting down, the flue gas temperature will not be in the optimal range and the normal BACT limits cannot be met.

The Emerson Smart Processor does not increase the flue gas temperature. The EPA Air Pollution Control Cost Manual states "At lower load profiles, the temperature within the boiler is lower. Variations in the flue gas temperature make design and operation of an SNCR system more difficult."

The Department never claimed that 95% reduction of NO_x can be achieved with an SNCR system. In fact, for retrofits it is less than 50% and on new facilities it is generally less than 60%. Figure 1.3 shows theoretical NO_x reduction which is never achieved in practice.

The Department and Minnkota has considered the other technologies in Comment VI (see Appendix A of Minnkota's assessment and p. 57-62 of the Department's preliminary determination). Each of these technologies have been rejected for various reasons. The commenter provided no reason why the rejection of these technologies was incorrect.

Heating of the flue gas during startup or shutdown would be impractical and not cost effective because of the large volume. There is no natural gas available and generation of heat for the flue gas would produce additional air pollutants including NO_x, CO, CO_2 and perhaps SO_2 and particulate matter.

Comment X: The proposed NO_x emission limit associated with the proposed BACT is not consistent with other emission rates achieved across the United States

Response: The commentor compares the proposed BACT with those of other sources without consideration to the type of boiler. The Choctaw Generating Station is a circulating fluidized bed boiler with no NO_x controls. The Stanton Station Units 1 and 10 are wall-fired and tangentially fired respectively, again with no NO_x control. The MRYS boilers are cyclone boilers with much higher uncontrolled NO_x emission rates, 0.85 lb/10^6 Btu and 0.79 lb/10^6 Btu (annual average) respectively. In order to do a fair comparison, the comparison must consider the type of boiler (i.e. cyclone). The comparisons provided by the commentor are inappropriate.

EPA

I. NDDH's Analysis of Technical Feasibility of Tail-End and Low Dust SCR at MRYS is Incorrect and Based on Incomplete Information

Response: EPA in footnote 6 attempts to equate the evaluation of low dust or tail-end SCR at the Gascoyne 500 Generating Station with that at the MRYS. The Gascoyne 500 Station was proposed as two circulating fluidized bed (CFB) boilers which use a dry scrubber and baghouse to control SO_2 and particulate emissions. MRYS Unit 1 is equipped with an electrostatic precipitator (ESP) and Unit 2 is equipped with a spray tower scrubber for SO_2 control and ESP for particulate. The comparison is faulty because it does not consider the type of boiler and the type of particulate control devices. Due to higher operating temperatures, a cyclone boiler produces more submicron aerosols of sodium and potassium which are concentrated in the fly ash which is not expected from the CFB. The baghouse at Gascoyne 500 will be approximately five times more effective in removing these submicron particles (Air and Waste Management Association; Air Pollution Engineering Manual). EPA did not provide any data to show the loading of catalyst deactivation chemical would be similar.

EPA also insinuates that the Department made a definitive interpretation that low dust or tail-end SCR was technically feasible for Gascoyne 500 and this determination should apply to MRYS. In its analysis, the Department stated "However, the Department is not certain that this technology (tail-end SCR) will work with a North Dakota lignite-fired unit because it has not been used before. For these reasons, the Department retained, with reservations, it as a technologically feasible control option." (Note - this technology was ultimately eliminated based on its high cost). In the BACT analysis prepared by Westmoreland they discuss the difficulties in getting the technology to work and state "Due to the presence of alkali constituents, especially Na, in lignite-fired flue gas, SCR has not been installed or demonstrated to be technically feasible on a lignite-fired boiler." Regarding low dust SCR, Westmoreland stated "Given the concern for catalyst poisoning and fouling with a high dust SCR, it may [emphasis added] be possible to design a low dust SCR system to control NO_x emissions downstream of the particulate control device." In this case, the particulate control device is a baghouse which is expected to be five times more efficient in removing the submicron catalyst deactivation chemicals. Westmoreland and the Department never said that a low dust system could be made to work. Westmoreland stated "Low dust SCR has not been used to control NO_x emissions from a CFB boiler. The low dust SCR configuration described above would be a first-of-its-kind design, and it is likely that Westmoreland would incur significant engineering and testing to ensure the viability of a low dust SCR control system on a lignite-fired CFB boiler." It is obvious that pilot scale testing would be required to determine the viability of a low dust SCR (both Haldor and CERAM will not provide a guarantee to Minnkota without pilot scale testing). The Westmoreland BACT analysis was prepared and submitted in June 2006 which is prior to Minnkota's BACT analysis (October 2006).

EPA's comparison of the MRYS BACT to the Gascoyne 500 BACT is inappropriate because of the different type of boilers, the different type of particulate control devices, the lignite is from a different mine and Minnkota conducted a much more thorough analysis.

Coyote Station Pilot Testing

The Coyote Station pilot testing does show a difference between subbituminous coal and North Dakota lignite. The EERC has described the blinding and plugging (deactivation) at the Coyote Station as extremely rapid and severe as compared to testing at the Columbia and Baldwin Stations which burn subbituminous coal. The pilot testing indicates that an SCR system designed for a plant that burns subbituminous coal may not be appropriate for a plant that burns North Dakota lignite. Additional research and testing on the effects of the flue gas constituents are required to determine if TESCR and LDSCR are a viable option for controlling NO_x emissions (Haldor Topsoe has indicated that the potential exists that the physical deactivation due to catalyst blinding and plugging could be severe enough to make SCR a nonviable option for controlling NO_x).

MRYS Unit 1 Sampling

The testing at MRYS 1 shows that some of the sodium aerosols will escape capture by the electrostatic precipitator. Minnkota has indicated that the sodium aerosols will have a mean diameter of 0.1 microns. The spray tower at MRYS Unit 2 is designed for SO_2 control, not particulate control. A spray tower designed for particulate control will generally have a very low removal efficiency for particles of this size. Wark and Warner (Air Pollution Control) and the Air and Waste Management Association (Air Pollution Engineering Manual) indicate less than 10% removal efficiency of these size particles. EPA's Air Pollution Control Technology Fact Sheet (EPA-452/F-03-016) states that spray tower scrubbers are not suited for fine particulate control. It goes on to state they are relatively inefficient in removing fine PM. EPA's Module 6: Air Pollutants and Control Techniques - Particulate Matter - Control Techniques indicates an average efficiency of less than 40% for 0.1 micron particles for a unit specifically designed to remove particulate matter. The scrubber at MRYS Unit 2 is designed for SO_2 control and is expected to be less efficient than average for particulate matter. EPA has provided no references to assert that the spray tower will be highly effective in removing aerosols with a mean diameter of 0.1 microns. Testing by Markowski[25] and Microbeam Technologies, Inc.[19] have confirmed that the wet scrubber is relatively ineffective in removing the submicron particles. Both CERAM Environmental and Haldor Topsoe, Inc. found the loading and form of the aerosols and particles in the flue gas at MRYs to be so significant that they would not provide a catalyst life guarantee for LDSCR or TESCR.

Minn-Dak Farmers Coop. Experience

The experience at Minn-Dak was intended to show that the submicron sodium aerosols will not be completely removed by particulate control devices and a fraction will be emitted. Minn-Dak is equipped with a venturi scrubber which is specifically designed for particulate control. For 1 micron particles, a venturi scrubber is expected to be more efficient than an ESP (Wark & Warner, Air Pollution Its Origin and Control). Wark & Warner further indicate that an ESP is expected to have less than a 10% efficiency for removal of 0.1 micron particles. The Minn-Dak experience verifies that the submicron sodium particles will not be captured even by a high efficiency wet scrubber designed to control particulate matter.

SCR System and Catalyst Vendor Responses on TESCR

Vendor guarantees alone do not prove that a technology will work (NSR Manual, Section I.V.B, p. B20). The Department considers vendor guarantees to be of little value unless there is a binding contract. No such guarantees exist for MRYS. In 2008, EPA provided emails which suggested that a catalyst life guarantee could be obtained from catalyst vendors. However, Minnkota requested proposals from CERAM Environmental and Haldor Topsoe, Inc. for LDSCR and TESCR in 2009. Both vendors indicated they would not provide a guarantee without pilot scale testing. After reviewing detailed information about the flue gas characteristics at MRYS, CERAM and HTI apparently decided the financial risk was too great to provide a guarantee.

Minnkota and its consultants provided information on a recent SCR test program in the southeast United States which caused the catalyst vendors to significantly modify and/or completely withdraw the guarantees they had offered prior to the testing. Minnkota indicates there has never been any tail-end SCR applied to any type of boiler burning lignite, whether in Europe or North America. In addition, Minnkota indicates no tail-end SCRs have been installed on any coal-fired utility boiler anywhere in the world since 1991. The fact that no tail-end SCR has been applied to a lignite-fired boiler and none have been constructed since 1991 on any type of coal-fired boiler leads the Department to question the amount of study and evaluation that was conducted by the vendors prior to making a so-called guarantee.

Conclusion of TESCR and LDSCR Technical Feasibility

LDSCR and TESCR are evaluated together since the flue gas characteristics at each location would not vary significantly and both vendors from which Minnkota had sought proposals (HTI and CERAM) both indicated they would not provide a guarantee for either location.

The NSR Manual states in Step 1:

> "Add-on controls on the other hand, should be considered based on the physical and chemical characteristics of the pollutant-bearing emission stream. Thus, candidate add-on controls may have been applied to a broad range of emission unit types that are similar, insofar as emissions characteristics, to the emissions unit undergoing BACT review."

The flue gas characteristics of the MRYS are significantly different from other boilers where SCR has been applied. Minnkota has supplied a significant amount of material which clearly shows the difference. CERAM stated in their proposal to Minnkota that "The high levels of Na_2O in the ash for the North Dakota lignite are not commonly found in sub-bituminous and bituminous coals which are fired with SCR systems. CERAM is unaware of any SCR application experience in the industry with this level and form of sodium in the ash." HTI[4] has stated "... the potential exists that physical deactivation due to catalyst blinding and plugging could be severe enough to make SCR a non-viable option for controlling NO_x emissions." Regarding North Dakota lignite, Sargent and Lundy (S&L) has stated "There are attributes of this fuel in a tail-end SCR environment that are not well understood today and need more investigation to predict its performance to make it a commercially available technology[13]." S&L also stated "Some important unanswered questions pose a significant risk for an SCR design engineer for tail-end SCR." Both HTI and CERAM have indicated in their October 2009 proposals they will not provide a guarantee for the catalyst life without successful pilot scale testing being done.

The NSR Manual states "Two key concepts are important in determining whether an undemonstrated technology is feasible: "availability" and "applicability." As explained in more detail below, a technology is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. Availability in this context is further explained using the following process commonly used for bringing a control technology concept to reality as a commercial product:

- concept state;
- research and patenting;
- bench scale or laboratory testing;
- pilot scale testing;
- licensing and commercial demonstration; and commercial sales.

A control technique is considered available, within the context presented above, if it has reached the licensing and commercial sales stage of development. <u>A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, technologies in the pilot scale testing stages of development would not be considered available for BACT review"</u> (emphasis added).

The MYRS is a new and dissimilar source category from other facilities where SCR has been successfully applied. The U.S. Environmental Protection Agency (EPA) has considered cyclone (and more generally slag tap) furnaces that burn lignite from North Dakota, South Dakota and Montana to be a separate source category for NO_x emission limits in 40 CFR 60 Subparts D and Da. This was due to the high sodium content of the lignite (43 FR 9276). Not until EPA established a fuel and furnace type neutral standard was all subcategorization eliminated. The Department is not aware of any analysis of the flue gas characteristics of North Dakota lignite by EPA which was considered when the subpart Da standards were revised. EPA states:

> "EPA disagrees that lignite-fired steam-generating units would not be able to achieve the amended NSPS. While there are no existing lignite-fired electric utility steam-generating units with SCR in the United States, there is considerable experience in the industry to show that use of SCR on lignite is technically feasible. EPA has concluded that the primary reason that no pulverized lignite-fired units are equipped with SCR is because no new pulverized lignite unit has been built in the United States since 1986.
>
> The Electric Power Research Institute testing of SCR catalyst in a slipstream at the Martin Lake Power showed acceptable results from Gulf Coast lignite. In addition, two recent

permit applications for pulverized lignite-fired utility units in Texas (Twin Oaks 3 and Oak Grove facilities) propose to use SCR to control NO_x emissions to 0.07 and 0.10 lb/MMBtu, respectively. Finally, technology suppliers report that SCR has been successfully used on lignite and brown coal boilers in Europe. EPA has concluded that SCR can be used on lignite boilers in the United States and catalyst suppliers have indicated that they will offer performance guarantees on these applications."

"In addition, the use of SCR is not required to comply with the amended NO_x standard. The existing Big Brown facility in Texas burns pulverized Gulf Coast lignite and is able to achieve 0.15 lb NO_x/MMBtu with combustion controls alone. EPA has concluded that new lignite-fired units would either be able to achieve the amended standards without the use of any backend controls or could use SNCR to comply. Existing units at 0.15 lb/MMBtu would only need 30 percent NO_x reduction to comply with the amended NO_x standard. This level of control has been demonstrated for existing pulverized coal (PC) units retrofit with SNCR, and new units could achieve even better results.

Fluidized bed combustion and gasification are also options for new lignite units. The proposed permits for the Westmoreland and South Heart facilities in North Dakota both propose to burn Fort Union lignite in fluidized beds and use SNCR to achieve a NO_x emissions limits of 0.09 lb/MMBtu. With regard to size, Foster Wheeler recently designed a 460 MW supercritical fluidized bed." (71 FR 9870)

Several of EPA's statements are erroneous for North Dakota lignite. There is not considerable experience in the industry to show the use of SCR for North Dakota lignite fired unit is technically feasible. CERAM has stated they are unaware of any SCR application experience in the industry with the level and form of sodium in the ash at MRYS. CERAM[3] also stated "the levels of K_20 in the North Dakota lignite ash are in the high end range found in many biomass fuels, such as wood and switch grass. However, the levels of Na_2O are much greater than that found in biomass or coal-fired SCR applications." S&L has indicated that unanswered questions about the flue gas characteristics and their effect on an SCR pose a significant risk. EPA's own consultant indicated he was not aware of any facility with as high of sodium loading as MRYs where SCR had been applied.[16]

EPA also indicated that SCR was shown to work on Gulf Coast lignite, Texas lignite and European brown coals. EPA concluded that SCR can be used on lignite boilers and that performance guarantees can be obtained from catalyst suppliers. Minnkota has clearly demonstrated that the ash from MRYS is different from Gulf Coast lignite, Texas lignite and European brown coals where SCR has been applied. CERAM[26] and HTI[27] both have indicated that they have offered catalyst life guarantees for other lignite fired units, including Texas lignite; however, they have refused to provide a catalyst life guarantee for MRYS which burns North Dakota lignite. The criteria EPA used to determine that SCR was technically feasible for NSPS purposes, is unclear. Under the PSD program, technical feasibility determinations are based on the flue gas characteristics of the source evaluated. EPA's second thought in their justification for the fuel and furnace type neutral standard was that a fluidized bed combustion unit could be used to meet the limits. The MRYS consists of existing cyclone fired units combusting North Dakota lignite and must be evaluated on this basis.

As CERAM pointed out, the flue gas characteristics of MRYS are different from other facilities where SCR has been applied. HTI has indicated that these fuel gas characteristics may cause so severe catalyst deactivation that SCR may not be a viable option for controlling NO_x emissions. These statements clearly indicate that the MRYS, and cyclone boilers burning North Dakota lignite, is a dissimilar source category from other sources that have successfully applied SCR.

Both CERAM and HTI believe pilot scale testing must be conducted prior to providing any guarantees for catalyst life. S&L has also recommended that pilot testing be conducted to answer questions about the effects of the soluble alkalis and ash characteristics including the size, stickiness and abrasiveness qualities of the ash.

There has never been a full scale SCR installed on a facility that burns North Dakota lignite. The high soluble sodium content (catalyst poison) and the sticky nature of the ash are characteristics that are different from facilities where SCR has been successfully applied. CERAM and HTI have supplied guarantees for catalyst at other lignite-fired facilities but would not provide one for MRYS. They have indicated they are not aware of any SCR being installed in the United States without a catalyst life guarantee. An SCR that is guaranteed to work successfully is not available for the MRYS.

The NSR Manual[1] states that technologies in the pilot scale testing phase of development need not be considered as available control technologies. Both CERAM and HTI have indicated that pilot scale testing is needed and would not provide a catalyst life guarantee. HTI has indicated that SCR may not be a viable option for MRYS. Pilot testing would be necessary to show whether SCR is a viable option. Minnkota is not required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is Minnkota required to experience extended trials to learn how to apply SCR to MRYS which is a new and dissimilar source type. CERAM and HTI have indicated that up to one year of pilot scale testing is required before they would consider a guarantee. This is consistent with Sargent and Lundy's (S&L) recommendation of one year of operation of a pilot scale test. S&L indicated that the overall pilot scale test program duration would be 18-24 months based on one year of operation. The additional time is for design, mobilization, setup and evaluation of the data. Estimates of the cost of pilot scale testing have ranged up to two million dollars (S&L Presentation March 11, 2009). This level of resource penalties and time delays are not required by BACT. Therefore, SCR is not an available technology for the MRYS.

The NSR Manual states "Technical feasibility of technology transfer control candidates generally is addressed based on an evaluation of pollutant-bearing gas stream characteristics for the proposed source and other source types to which the control had been applied previously." (Section IV.B, p.B.21)

"A demonstration of technical infeasibility is based on a technical assessment considering physical, chemical and engineering principles and/or empirical data showing that he technology would not work on the emissions unit under review, or that unresolvable technical difficulties would preclude the successful deployment of the technique." (Section IV.B, p.B.20)

"Generally, decisions about technical feasibility will be based on chemical and engineering analysis in conjunction with information about vendor guarantees." (Section IV.B, p.B.20)

The lignite combusted at MRYS contains high quantities of soluble sodium and potassium which can cause catalyst reaction site poisoning, blinding, and plugging of catalyst pores and channels. Core samples for 2007-2010 indicated a sodium oxide (Na_2O) concentration in the ash as high as 13.4% and a potassium oxide (K_2O) concentration as high as 6.9% (Appendix A-2, 4/23/07 submittal). During combustion of this fuel, a significant portion of these organically associated elements are either vaporized or form small particles that leave the boiler in the flue gas. Soluble sodium and potassium are catalyst poisons even in dry conditions in the SCR. The sodium and potassium can also form sulfates that plug the catalyst pores and channels. HTI has stated for LDSCR and TESCR that physical deactivation due to catalyst binding and plugging could be severe enough to make SCR a non-viable option for controlling NO_x emissions. CERAM has stated that the levels of K_2O in the North Dakota lignite ash are at the high end of the range found in many biomass fuels; however, the levels of Na_2O are much greater than that found in biomass or coal-fired SCR applications. The potential clearly exists that LDSCR and TESCR cannot be successfully applied at MRYS.

The NSR Manual states that decisions about technical feasibility will be based on chemical, and engineering analysis in conjunction with information about vendor guarantees. Both HTI and CERAM refused to provide catalyst life guarantees for MRYS. Both companies have indicated that refusal to provide a catalyst guarantee is extremely rare. They both indicated they have offered guarantees for other types of lignite (including Texas lignite), European brown coals and biomass. Both companies indicated they were not aware of any SCR being installed in the United States without a catalyst life guarantee. In a letter to Burns and McDonnell (July 27, 2010), HTI stated:

> "HTI currently has one of the first SCR's on a unit firing Texas lignite, where HTI provided a full 3 year catalyst life guarantee along with typical NO_x removal effects, ammonia slip, SO_2 oxidation rates, and pressure drop guarantees. Performance of this SCR has been excellent since start-up. HTI also has the majority of the biomass fired applications in the U.S. and the majority of the IGCC applications in the world. All of these are new and very challenging projects which push the technology to the next level.
>
> HTI does not avoid challenging applications, but we do review the technical as well as financial risks associated with each project. If the risk level is too high then we may choose not to participate in the project or only provide catalyst without performance guarantees."

Apparently, the risk of failure at MRYS was too great for HTI since they would not supply a catalyst life guarantee. SCR is not applicable to MRYS.

EPA has indicated that BACT is intended as a "technology forcing" requirement. HTI has indicated they have "forced" the technology (SCR) at other facilities and provided guarantees. Apparently, the use of SCR at MRYS forces the technology beyond an acceptable risk for the company. The same is apparently true for CERAM. Both companies have indicated that their decision not to provide a guarantee was not influenced by Minnkota or Burns and McDonnell. It was a business decision based on the risk involved.

The Department of Justice, through their contractor Evonik Energy Services, LLL (Evonik) provided a Request for Proposals (RFP) to HTI and CERAM supposedly based on the flue gas characteristics of MRYS. Both companies indicated they would provide catalyst life guarantees to Evonik based on the RFP. HTI and CERAM have provided letters explaining this seeming contradiction. Both have indicated that Evonik did not provide a fuel analysis, ash analyses, the range of fuel and ash characteristics that could be encountered , details on the soluble constituents in the flue gas and the fact that it was North Dakota lignite. HTI believed the RFP was for a facility burning eastern subbituminous coal. HTI indicated they would not have provided a guarantee if it had known that the fuel was North Dakota lignite. CERAM has indicated it would not have provided a guarantee if the Evonik RFP had provided the same level of detail as the Minnkota RFP. The RFP by Evonik and subsequent proposals by CERAM and HTI proved nothing and have no value.

The chemical constituents in the flue gas at MRYS are known to cause chemical poisoning of SCR catalyst, blinding of the catalyst and pluggage. The risk of failure of an SCR system at MRYS was so great that two catalyst vendors, HTI and CERAM, independently determined that they could not provide a catalyst life guarantee. Minnkota is not required under BACT to assume the high risk associated with the failure of a technology that has never been used on North Dakota lignite-fired unit. Therefore, the technology is currently not applicable to MRYS.

In order for a technology to be technically feasible it must both be available and applicable to the sources under review. Since LDSCR and TESCR are neither available or applicable to MRYS, the technology is not technically feasible for a lignite source. This is not the first BACT determination that deemed SCR was not technically feasible for a lignite source. The State of Louisiana determined that SCR was not feasible for the Red River Environmental Products, LLC activated carbon plant that uses lignite. This determination was based on a finding that the sodium sulfate in the flue could cause rapid deactivation of the catalyst and the lack of operating or empirical data.

Both CERAM[26] and HTI[27] have stated that they are not aware of an SCR being installed in the United States without a catalyst life guarantee. Minnkota is not required under BACT to assume the high risk associated with the failure of an SCR system.

Comment II: NDDH's Technical Feasibility Analysis of High Dust SCR is Incorrect and Based Upon Flawed Data

Response:

- HDSCR Catalyst Plugging and Deactivation

The NSR Manual[4], page B.20, states "A demonstration, of technical infeasibility is based on a technical assessment considering physical, chemical and engineering principles, and/or empirical data showing that the technology would not work on the emissions unit under review, or that unresolvable technical difficulties would preclude the successful deployment of the technique."

The Department asked EPA's consultant, Mr. Roger Christmann, if he was aware of any installation in the world where SCR had been applied to a facility with as high of sodium loading as at MRYS. Mr. Christmann indicated no.[16] CERAM Environmental, Inc., in their proposal for LDSCR and TESCR, has indicated that they are not aware of any SCR experience in the industry with the level and form of sodium in the flue gas at MRYS. Haldor Topsoe in their proposal for LDSCR has indicated that catalyst deactivation at MRYS could be so severe that LDSCR may not be a viable NO_x control. The concentration of the catalyst deactivation constituents at a HDSCR location would be as much as 90 times that at a LDSCR location. This indicates there has never been a design established for a flue gas with the chemical characteristics found at MRYS.

Simple mathematics prepared by the Department shows that the flue gas at MRYS is much higher in sodium and other catalyst deactivation chemicals than other power plant flue gases. EPA tries to dismiss this by ratioing the loading of PRB to bituminous without indicating the actual loading. The Department showed the actual loading (lb/dscf and lb/wscf) as well as the ratio to other facilities. When you start out with a very small loading, as is the case with bituminous coal, a large ratio for subbituminous coal also gives you small loading. EPA seems to ignore the fact that the sodium at MRYS is the soluble form (organically associated) which is a more potent catalyst deactivation chemical than the insoluble (inorganically associated) form found in other coals. As EPA's own consultant points out, SCR has never been applied to a sodium loading as high as MRYS.

Minnkota and its consultants have documented very well the effect of soluble sodium on an SCR catalyst. Although the Coyote testing did not provide any deactivation rate data for high soluble sodium North Dakota lignite, it did show that an SCR design for subbituminous coal may not work successfully with North Dakota lignite. As Sargent and Lundy pointed out, there is no known solution for the soluble alkalis such as the soluble sodium and potassium found in North Dakota lignite[17]. EPA ignores the chemical differences between Texas lignite and North Dakota lignite. With respect to the catalyst vendor guarantees provided in 2007 to Minnkota, all vendors indicated that pilot scale testing was either required or should be done prior to applying high dust SCR technology to a North Dakota lignite-fired boiler. The so called "guarantees" that SCR can be applied to MRYS are somewhat meaningless because there was no consequence for making an incorrect statement at that point in time. Only when a contract is signed between the source and vendor is there any consequence to the statement that SCR will work at the MRYS. This is apparent from the proposals CERAM Environmental and Haldor Topsoe made for TESCR and LDSCR in 2009. Each company refused to provide a guarantee without pilot testing. It can be inferred the same would be true for HDSCR.

The NSR Manual[4], page B.20, states "However, EPA does not consider a vendor guarantee alone to be sufficient justification that a control option will work." The NSR Manual[4] goes on to state "Generally, decisions about technical feasibility will be based on chemical and engineering analyses (as discussed above) in conjunction with information about vendor guarantees." Minnkota has provided information that indicates the potential for greatly reduced catalyst life due to the chemical characteristics of the flue gas. Although two vendors in 2007 indicated a catalyst life for HDSCR which the Department would consider as a "successful application" of SCR technology at MRYS, others did not give such an indication. All vendors indicated the flue gas temperature problems (too hot or too cold) must be resolved for the application of HDSCR to be successful. No solution to this problem has been found at this time. All vendors indicated that pilot scale testing should be conducted. Two of the companies that indicated in 2007 that they would provide a guarantee for HDSCR at MRYS have refused in 2009 to provide a guarantee for LDSCR or TESCR. A HDSCR will encounter much higher concentrations of catalyst deactivation chemicals. Although Texas has determined that SCR is technically feasible for Texas lignite, the chemical constituents of North Dakota lignite that affect the feasibility of SCR are quite different. CERAM and Haldor Topsoe have both offered catalyst life guarantees for Texas lignite; however, they have refused to offer a guarantee for the MRYS. The State of Louisiana recently determined that SCR was not technically feasible for an activated carbon plant because of the flue gas characteristics of the Gulf Coast lignite used in the process. The NSR Manual[4], pages B.19 - 20, indicates that an add-on control technology is only technically feasible if it can lead to "successful operation" or "successful deployment." The Department has indicated that anything less than 10,000 hours of catalyst life would not be successful operation of the SCR system and thus be technically infeasible. Based on the analysis of the chemical characteristics of the flue gas at MRYS, Minnkota has demonstrated that the flue gas characteristics of MRYS are different from other coal-fired boilers where SCR has been applied. CERAM has stated for LDSCR and TESCR that they are unaware of any SCR application experience in the industry with the level and form of sodium in the ash at MRYS[9]. It can be surmised that this is also true for HDSCR. The MRYS is a dissimilar source.

The NSR Manual[4] states "A source would not be required to experience time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type" (Chapter B, Section IV.B). Minnkota is not required to conduct extensive and expensive feasibility analyses for modifying the boiler to correct temperature problems that make HDSCR infeasible.

EPA has indicated that catalyst regeneration is a viable option (that is currently used in practice) for restoring catalyst life either in-situ, on-site, or off-site water washing. EPA cites a PowerPoint presentation at the 2007 NO_x Round Table and Expo by Reinhold Environmental Limited as evidence that this technique is available. DOJ's consultant, Mr. Hans Hartenstein, also made a presentation at the referenced Expo. In Mr. Hartinstein's presentation the following statement is made "Regeneration = Removal of catalyst poisons plus restoration of catalytically active ingredients - can typically not be done in-situ or on-site, but should be done off-site to ensure required close process control." EPA may be referring to "rejuvenation" of a catalyst for which Mr. Hartenstein states "Removal of catalyst poisons without the need for replenishing catalytically active compounds - can **sometimes** [emphasis added] be done in-situ, but is most commonly done either on-site or off-site." These statements were also made by Ehrnschwender and Holsccher at the February 2008 Expo (Considerations for Catalyst Deactivation and Regeneration When Firing Biomass). Minnkota and its consultants have addressed this issue by stating "Regarding the contention of Hartenstein, there is extremely limited experience with in-situ catalyst cleaning on coal-fired units. ENBW in Germany developed this technique, but it has never had a commercial success. It has also never been used for blinded or chemically poisoned catalyst, but only for mechanically plugged catalyst."[18] There is no evidence regarding the effectiveness of washing to rejuvenate an SCR catalyst on the MRYS. Pilot scale testing would be necessary to determine the feasibility of this catalyst management technique.

Microbeam Technologies, Inc. (Microbeam) conducted particulate emissions testing at the MRYS in March of 2009[19]. The results indicate that most of the particulate matter emissions from each boiler is removed by the electrostatic precipitator (ESP). Microbeam's results indicated a particulate matter removal efficiency of 99.76%. Microbeam's results also indicate the amount of Na_2O + K_2O is approximately 50-90 times greater entering the ESP than exiting the ESP. The results are similar for Na_2O + K_2O entering the ESP versus exiting the wet scrubber. The loading of Na_2O + K_2O on a HDSCR would be approximately 50-90 times higher than a LDSCR or TESCR. In the November 2008 technical feasibility analysis, the Department evaluated HDSCR and determined it was not technically feasible. The Department has reviewed the Microbeam Technologies report and reached the same conclusions regarding technical feasibility. The amount of sodium and potassium in the flue gas is so high that it is very unlikely that 10,000 hours of catalyst life could be achieved. The testing by Kling et. al. found deactivation rates up to 52% in 1,500 hours for a fuel made up of tree bark and 20% demolition waste. The Microbeam[19] results suggest a similar rate for MRYS. Zheng et. al. found a deactivation rate of 0.4% per day using 20-30 mg/Nm^3 of potassium sulfate with a mass mean diameter of 0.55 micrometers (u.m.). The 0.4% deactivation rate per day is equivalent to 6,000 hours to 100% deactivation. The Microbeam results indicate a higher potassium sulfate equivalent loading of aerosols less than 0.55 μm at MRYS. Both HTI and CERAM indicated changeout of the SCR catalyst at 50% deactivation[9,10]. This empirical data suggests that catalyst changeout for a HDSCR at MRYS will have to occur much more frequently than 10,000 hours per changeout.

Therefore, a commercial design of HDSCR for high soluble sodium North Dakota lignite is not available. Experience with subbituminous coal or bituminous coal is not applicable. Based on the guidance in the NSR Manual, HDSCR must be determined not to be technically feasible.

- MRYS Temperature Variation Issue Related to HDSCR

The resolution of the temperature problem would require a technical feasibility analysis of a "very complex nature" (Steve Moorman 7/18/07 email) to determine if boiler modifications could bring furnace exit gas temperatures into the range needed for compatibility with the operation of HDSCR. Modifications outside of the boiler may solve the temperature problem; however, a study would be required. Babcock and Wilcox estimated the cost of the study at $275,000 - $400,000 and would take 20-24 weeks to complete. Minnkota is not required to undergo expensive and lengthy time delays in order to learn how to apply SCR technology. The temperature problem is another potentially fatal road block to the successful use of HDSCR. EPA's statement that the technical issues with the temperature issue can be resolved appears to be premature.

EPA's Conclusion on HDSCR

When considering application of HDSCR to a cyclone boiler burning North Dakota lignite, the MRYS is considered a new source type. EPA has recognized cyclone boilers, and more generally slag tap furnaces, that burn lignite from North Dakota, South Dakota and Montana as a separate source category for NO_x emissions in the New Source Performance Standards, Subparts D and Da. This separate category was established primarily based on the use of high sodium lignite. Not until EPA went to a fuel and furnace neutral standard was this category replaced. The replacement of this category was apparently done without an evaluation of the flue gas characteristics of North Dakota lignite. The NSR Manual states "Add-on controls, on the other hand, should be considered based on the physical and chemical characteristics of the pollutant-bearing emission stream. Thus, candidate add-on controls may have been applied to a broad range of emission unit types that are similar, insofar as emissions characteristics, to the emission unit undergoing BACT review." (NSR Manual, Chapter B, Section IV.A).

Minnkota was unable to obtain a catalyst life guarantee for LDSCR and TESCR. It follows that a guarantee is also not available for HDSCR which will have worse flue gas conditions for the SCR catalyst. Empirical data suggest the catalyst will have to be replaced much more frequently than every 10,000 hours of operation. The temperature problem may be unresolveable. Therefore, HDSCR is not available or applicable and is technically infeasible.

Comment III: The NDDH BACT Determination Incorrectly Applies the Concept of Pilot Testing in EPA's NSR Manual to Conclude that SCR is not Technically Feasible.

Response: EPA states that "For determining whether a control option is available, EPA's NSR Manual does not describe the comparison of gas stream characteristics between the source under review and other sources."

Whether MRYS is a new or dissimilar source is based on the flue gas characteristics. Chapter B, Section IV.A, p. B.10, Identify Alternative Emission Control Techniques (Step 1) states "The top-down BACT analysis should consider potentially applicable control techniques from all three categories. Lower polluting processes should be considered based on demonstrations made on the basis of manufacturing identical or similar products from identical or similar raw materials or fuels. Add-on controls, on the other hand, should be considered based on the physical and chemical characteristics of the pollutant-bearing emission stream. Thus, candidate add-on controls may have been applied to a broad range of emission unit types that are similar, insofar as emissions characteristics, to the emissions unit undergoing BACT review" (emphasis added). Clearly, identification of "potentially available" control options under Step 1 must take into account the flue gas characteristics. There has never been SCR technology applied to a boiler that combusts North Dakota lignite. EPA has recognized, in the past, cyclone boilers, such as those at Minnkota, that burn lignite from North Dakota is a separate source category for NO_x emission limits under the New Source Performance Standards, Subpart D and Da. Minnkota has shown that the flue gas characteristics at MRYS are different from that at any other coal-fired power plant where SCR has been installed. Mr. Roger Christmann, EPA's consultant, stated that he was not aware of any power plant where SCR had been applied with as high of sodium loading as MRYS[16]. CERAM Environmental has stated that it is unaware of any SCR application experience in the industry with the level and form of sodium in the MRYS ash[9]. Haldor Topsoe has stated that SCR (HDSCR, LDSCR and TESCR) may not be a viable option for controlling NO_x emissions due to catalyst pluggage and blinding[10]. MRYS is a new and dissimilar source from any source category where SCR has been applied successfully.

SCR technology designed for other coal-fired power plants may not be applicable to a North Dakota lignite-fired unit and there is no commercially available design. The experience at other coal-fired boilers is not applicable. Pilot scale testing would be necessary to show whether SCR can work successfully. As Sargent and Lundy (S&L)[13] pointed out, there are no known solutions for the catalyst surface masking and catalyst deactivation caused by the soluble alkalis (Na_2O and K_2O) found in North Dakota lignite. S&L indicated that some thresholds or limits are yet to be defined for SCR involving ash with greater than 2% Na_2O and greater than 1% K_2O. The Na_2O in the ash at MRYS can be as high as 13% and K_2O as high as 7%. S&L has also stated "there are attributes of this fuel in an SCR environment that are not well understood today and need more investigation to predict its performance." Any pilot scale testing would be used to obtain data on the soluble alkalis and ash characteristics and compare the findings with experience on Power River Basin Coal to determine if SCR can be applied successfully to a unit firing ND lignite.

The pilot scale testing would not be for optimizing an existing available control technology. It would be for determining whether SCR is a viable control option, researching solutions to the high concentration of soluble alkalis and the possibility of designing an SCR system for a new and dissimilar source category.

Comment IV: The NDDH BACT Determination Frustrates the Technology Forcing Function of the BACT that was Intended by Congress.

Response: MRYS is a different source category based on its flue gas characteristics. The Department has taken the position that the flue gas characteristics at the MRYS will preclude the successful application of existing SCR technology.

Haldor Topsoe has stated in a July 27, 2010 letter to Burns and McDonnell the following: "HTI currently has one of the first SCRs on a unit firing Texas lignite, where HTI provided a full 3 year catalyst life guarantee along with typical NO_x removal effects, ammonia slip, SO_2 oxidation rates, and pressure drop guarantees. Performance of this SCR has been excellent since start-up. HTI also has the majority of the biomass fired applications in the U.S. and the majority of the IGCC application in the world. All of these are new and very challenging projects which push the technology to the next level. HTI does not avoid challenging applications, but we do review the technical as well as financial risks associated with each project. If the risk level is too high then we may choose not to participate in the project or only provide catalyst without performance guarantees."

Clearly Haldor Topsoe believes that "forcing" SCR technology for MRYS presents an unacceptable risk for their company since they would not provide a catalyst guarantee for LDSCR or TESCR. CERAM Environmental also would not provide a guarantee[9]. Again, apparently the risk of failure was too great.

Decisions regarding technical feasibility are based on the flue gas characteristics, not whether it has been applied to a coal-fired boiler or some other general source category. We believe Congress never intended forcing a technology on a source when there is a low probability of successful deployment of that technology.

Comment V: Other Comments on the NDDH BACT Determination.

Comment 1: EPA does not agree with the statement "Information from Sargent and Lundy indicates that not enough information is available to determine whether SCR technology can be successfully adapted to units burning North Dakota lignite."

Response: Sargent and Lundy[17] indicates that there are no known solutions to the surface masking from soluble alkalis (Slide 49) and no known solution to the catalyst deactivation by soluble alkalis (Slide 52). In addition, S&L states that "There are attributes of this fuel in an SCR environment that are not well understood today and need more investigation to predict its performance (Slide 82)." Without knowing the performance of an SCR, one cannot say it can be successfully adapted to North Dakota lignite.

Comment 2: EPA believes control of popcorn ash is not a significant problem.

Response: The Department agrees that recent experience indicates that popcorn ash can be adequately controlled.

Comment 3: EPA believes coal cleaning needs to be addressed.

Response: The issue of coal cleaning for NO_x reduction was addressed by Minnkota in their analysis (see p. 3-10 and 3-11). There is no evidence that coal cleaning will reduce the boiler NO_x emissions.

EPA suggested in their comments that coal cleaning could remove the soluble sodium and potassium elements in the coal. The sodium and potassium are organically bound within the coal particles. Physical coal cleaning can remove only matter that is physically distinct from the coal, such as small dirt particles, rocks and pyritic sulfur. Physical cleaning cannot remove contaminants that are chemically combined with coal. It also cannot remove nitrogen from the coal (Noyes, Robert; Pollution Prevention Technology Handbook, 1993).

Chemical cleaning of the lignite may remove some of the chemically bound sodium and potassium. EPA did not site any examples of facilities that are removing chemically bound sodium or potassium. The Department has not found any coal cleaning plants that remove the organically associated sodium and potassium from coal. Therefore, the technology is not commercially available and therefore, technically infeasible.

Comment 4: EPA would like the email from Mr. Brad Plummer included in the record.

Response: Agreed.

Comment VI: Docket Information for the TXU Oak Grove NSR Permit is Evidence that the Utility Industry and Other State Agencies Believe that SCR is Technically Feasible & can be Applied to New Fuel Types & Boiler Types.

Response: The NSR manual[4] states "A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review" (Chapter B, Section II.A). The flue gas characteristics of Texas lignite are significantly different from North Dakota lignite. North Dakota lignite ash contains much more sodium and potassium and it is in the soluble form. This soluble form penetrates deeply into the pores of the catalyst and causes premature failure of the catalyst. Minnkota has provided sufficient evidence that the flue gas characteristics could preclude successful application of SCR technology. Both Haldor Topsoe[27] and CERAM[26] have indicated they have offered guarantees for Texas lignite. However, they have refused to provide a guarantee for North Dakota lignite. Any comparisons of North Dakota lignite to Texas lignite for application of SCR is inappropriate.

Regarding other state's BACT determinations, the State of Louisiana recently determined that SCR was not technically feasible at an activated carbon plant (Red River Environmental Products, LLC) that uses Gulf Coast lignite as a feedstock. This determination was based on a conclusion that the flue gas characteristics (i.e. alkali metals, especially sodium) would deactivate the catalyst and preclude successful deployment of SCR technology. EPA did not object to Louisiana's BACT determination.

Comment VII: B&McD 114 Response Documents.

Response: No response necessary.

Comment VIII: Docket Information for the Clean Air Interstate Rule (CAIR), Best Available Retrofit Technology, and New Source Performance Standards (NSPS) States that EPA Determined that SCR is Technically Feasible for Lignite-Fired Utility Boilers.

Response: The MYRS is a new and dissimilar source category from other facilities where SCR has been successfully applied. The U.S. Environmental Protection Agency (EPA) has considered cyclone (and more generally slag tap) furnaces that burn lignite from North Dakota, South Dakota and Montana to be a separate source category for NO_x emission limits in 40 CFR 60 Subparts D and Da. This was due to the high sodium content of the lignite.[24] Not until EPA established a fuel and furnace type neutral standard was all subcategorization eliminated. The Department is not aware of any analysis of the flue gas characteristics of North Dakota lignite by EPA which was considered when the subpart Da standards were revised. EPA states:

> "EPA disagrees that lignite-fired steam-generating units would not be able to achieve the amended NSPS. While there are no existing lignite-fired electric utility steam-generating units with SCR in the United States, there is considerable experience in the industry to show that use of SCR on lignite is technically feasible. EPA has concluded that the primary reason that no pulverized lignite-fired units are equipped with SCR is because no new pulverized lignite unit has been built in the United States since 1986.
>
> The Electric Power Research Institute testing of SCR catalyst in a slipstream at the Martin Lake Power showed acceptable results from Gulf Coast lignite. In addition, two recent permit applications for pulverized lignite-fired utility units in Texas (Twin Oaks 3 and Oak

Grove facilities) propose to use SCR to control NO_x emissions to 0.07 and 0.10 lb/MMBtu, respectively. Finally, technology suppliers report that SCR has been successfully used on lignite and brown coal boilers in Europe. EPA has concluded that SCR can be used on lignite boilers in the United States and catalyst suppliers have indicated that they will offer performance guarantees on these applications."

"In addition, the use of SCR is not required to comply with the amended NO_x standard. The existing Big Brown facility in Texas burns pulverized Gulf Coast lignite and is able to achieve 0.15 lb NO_x/MMBtu with combustion controls alone. EPA has concluded that new lignite-fired units would either be able to achieve the amended standards without the use of any backend controls or could use SNCR to comply. Existing units at 0.15 lb/MMBtu would only need 30 percent NO_x reduction to comply with the amended NO_x standard. This level of control has been demonstrated for existing pulverized coal (PC) units retrofit with SNCR, and new units could achieve even better results.

Fluidized bed combustion and gasification are also options for new lignite units. The proposed permits for the Westmoreland and South Heart facilities in North Dakota both propose to burn Fort Union lignite in fluidized beds and use SNCR to achieve a NO_x emissions limits of 0.09 lb/MMBtu. With regard to size, Foster Wheeler recently designed a 460 MW supercritical fluidized bed." (71 FR 9870)

Several of EPA's statements are erroneous for North Dakota lignite. There is not considerable experience in the industry to show the use of SCR for North Dakota lignite fired unit is technically feasible. CERAM[9] has stated they are unaware of any SCR application experience in the industry with the level and form of sodium in the ash at MRYS. CERAM also stated "the levels of K_20 in the North Dakota lignite ash are in the high end range found in many biomass fuels, such as wood and switch grass. However, the levels of Na_2O are much greater than that found in biomass or coal-fired SCR applications." S&L[13] has indicated that unanswered questions about the flue gas characteristics and their effect on an SCR pose a significant risk.

EPA also indicated that SCR was shown to work on Gulf Coast lignite, Texas lignite and European brown coals. EPA concluded that SCR can be used on lignite boilers and that performance guarantees can be obtained from catalyst suppliers. Minnkota has clearly demonstrated that the ash from MRYS is different from Gulf Coast lignite, Texas lignite and European brown coals where SCR has been applied. CERAM[26] and HTI[27] both have indicated that they have offered catalyst life guarantees for other lignite fired units, including Texas lignite; however, they have refused to provide a catalyst life guarantee for MRYS which burns North Dakota lignite. The criteria EPA used to determine that SCR was technically feasible for NSPS purposes, is unclear. Under the PSD program, technical feasibility determinations are based on the flue gas characteristics of the source evaluated. EPA's second thought in their justification for the fuel and furnace type neutral standard was that a fluidized bed combustion unit could be used to meet the limits. The MRYS consists of existing cyclone fired units combusting North Dakota lignite and must be evaluated on this basis.

The decision of technical feasibility of add-on controls under the PSD BACT process is based on the flue gas characteristics of the source under review. EPA has provided no technical analysis of the flue gas characteristics of North Dakota lignite, which is different from other lignites, to show its reasoning that SCR is technically feasible under the CAIR rule, BART Guidelines and NSPS. EPA's criteria for determining technical feasibility under these rules is unclear. Without such an analysis, the decisions under the cited rules and guidelines are immaterial. It should be noted that the CAIR rule did not include North Dakota sources and has been vacated by the Circuit Court of Appeals for the District of Columbia. MRYS is not subject to the BART Guidelines or the NO_x standards under the NSPS.

All information provided by EPA will be included in the record.

Comment IX: Hans Hartenstein Expert Report on "Feasibility of SCR Technology for NO_x Control Technology for the Milton R. Young Station, Center, North Dakota.

Response: The expert report is based on several premises that are incorrect. These include:

Premise 1: Sodium is not a poison to catalyst at SCR operating temperatures. Moisture is needed to carry soluble sodium into catalyst pores before it can poison the catalyst.

Response: Soluble sodium has been found to be an SCR catalyst poison at normal SCR operating temperatures (Haldor Topsoe[10], Zheng et.al.[21], Kling et.al.[20], Guo,[23] Baxter[22]). CERAM Environmental has indicated in their Confidential Proposal for LDSCR and TESCR that soluble sodium will cause SCR deactivation even in dry conditions. This is consistent with the findings of Kling et.al.[20] and Zheng et.al.[21] that submicron aerosols of sodium migrate into the catalyst pores, most likely by surface diffusion, and deactivate the catalyst.

Premise 2: Vendors will supply guarantees for HSDSCR, LDSCR and TESCR.

Response: The Confidential Proposals for LDSCR and TESCR by CERAM Environmental and Haldor Topsoe indicated they would not provide a guarantee without pilot scale testing. This is in contrast to Hartenstein's statements that these companies assured him they would provide guarantees. It is virtually assured these companies would not provide a guarantee for HDSCR without pilot scale testing.

Premise 3: There is other experience with coal-fired power plants that can be utilized for designing an SCR for M.R. Young Station.

Response: CERAM Environmental, in their Confidential Proposal for LDSCR and TESCR, has indicated they are not aware of any SCR application experience in the industry with the level and form of sodium in the M.R. Young ash. Haldor Topsoe has indicated that the potential exists that physical deactivation due to catalyst blinding and plugging could be severe enough to make SCR a nonviable option for controlling NO_x emissions. S&L has indicated there are attributes of North Dakota lignite in an SCR environment that are not well understood and need investigation to predict its performance. These statements indicate that there is not enough experience with the flue gas characteristics at the MRYS to assure SCR can be applied successfully. This is also one of the reasons CERAM and HTI would not supply a catalyst life guarantee.

Premise 4: Sodium and other catalyst poisons will be removed by the wet scrubber prior to TESCR.

Response: Testing by Markowski[25] and Microbeam Technologies, Inc.[19] indicate that the wet scrubber on Unit 2 at the MRYS will not effectively remove the submicron aerosols that will cause SCR catalyst deactivation. A significant amount of sodium and potassium aerosols will be in the flue gas after the wet scrubber.

Premise 5: The same catalyst was used on the pilot scale testing at Baldwin Station and Coyote Station.

Response: Minnkota has indicated that fresh catalyst was used in the Coyote testing.

Premise 6: Temperature problems are no reason to reject SCR as technically infeasible since they can be easily fixed.

Response: High temperature will sinter the catalyst and deactivate it. All vendors indicated the high temperature problem must be resolved before HDSCR can be successfully applied. Babcock and Wilcox indicates that a study of the temperature problem would be very complex, cost $275,000 - $400,000, and take 20-24 weeks to complete. Minnkota is not required to undergo costly studies or extended delays in order to adapt a technology to their facility.

The faulty premises of Mr. Hartenstein's report has failed to demonstrate that HDSCR, LDSCR or TESCR is technically feasible for the MRYS.

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